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Source Assessment: Dry Bottom Utility Boilers Firing Pulverized Bituminous Coal

Monsanto Research Corp.
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Pulverized Fuels	Dry Bottom Boilers	
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by

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Source: Chemical Engineers' Handbook, Fifth Edition, J. H. Perry and C. H. Chilton, eds. McGraw-Hill Book Company, New York, New York, 1973.

Figure 9-11. Burner and furnace configurations for pulverized-coal firing. p. 9-21.

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Source: Betz Handbook of Industrial Water Conditioning, Betz Laboratories, Inc., Trevose, PA, 1976, pages 18-19.

Table on Water Impurities, Problems, and Treatment.

(*) Pages 20 and 21 (Table 6)

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Source: Standard Specification for Classification of Coals by Rank, Designation D 388-66 (Reapproved 1972). In: 1976 Annual Book of ASTM Standards, Part 26: Gaseous Fuels; Coal and Coke; Atmospheric Analysis. American Society for Testing and Materials, Philadelphia, Pennsylvania, 1976. pp. 211-215.

→ (Table 1. Classification of Coals by Rank. p. 214.

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Source: Edwards, J. B. Combustion: The formation and Emission of Trace Species. Ann Arbor Science Publishers, Inc., Ann Arober, Michigan, 1974. 240 pp.

Figure 68. Combustion of a solid. p. 151.

(*) Page 27 (Figure 6)

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PREFACE

The Industrial Environmental Research Laboratory (IERL) of the U.S. Environmental Protection Agency (EPA) has the responsibility for insuring that pollution control technology is available for stationary sources to meet the requirements of the Clean Air Act, the Federal Water Pollution Control Act, and solid waste legislation. If control technology is unavailable, inadequate, or uneconomical, then financial support is provided for the development of the needed control techniques for industrial and extractive processes and combustion sources. Approaches considered include: process modifications, feedstock modifications, add-on control devices, and complete process substitution. The scale of the control technology programs ranges from bench- to full-scale demonstration plants.

The Chemical Processes Branch of the Industrial Processes Division of IERL has the responsibility for developing control technology for a large number of industrial operations and combustion sources. As in any technical program, the first question to answer is, "Where are the unsolved problems?" This is a determination which should not be made on superficial information; consequently, each of the industries is being evaluated in detail to determine if there is, in EPA's judgment, sufficient environmental risk associated with the process to indicate that pollution reduction is necessary. This report contains the data necessary to make that decision for air emissions, water effluents, and solid residues from dry bottom utility boilers firing pulverized bituminous coal. This work falls under EPA's Conventional Combustion Environmental Assessment (CCEA) Program.

Monsanto Research Corporation has contracted with EPA to investigate the environmental impact of various industries which represent sources of pollution in accordance with EPA's responsibility as outlined above. Dr. Robert C. Binning serves as Program Manager in this overall program, entitled "Source Assessment," which includes the investigation of sources in each of four categories: combustion, organic materials, inorganic materials, and open sources. Dr. Dale A. Denny of the Industrial Processes Division at Research Triangle Park serves as EPA Project Officer. In this study of dry bottom utility boilers firing pulverized bituminous coal, Mr. Michael C. Osborne, Mr. John O. Milliken, and Dr. Ronald A. Venezia served as EPA Task Officers.

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ABSTRACT

This report describes and assesses the potential impact of air emissions, wastewater effluents, and solid wastes resulting from the operation of dry bottom utility boilers firing pulverized bituminous coal. Consuming approximately 3.2×10^8 metric tons of such coal per year, this source type consititutes the primary method of firing coal in utility boilers.

Air emissions were characterized from literature data supplemented by a field sampling program. Significant emissions resulting from coal combustion were particulate matter, sulfur oxides, nitrogen oxides, hydrocarbons, polycyclic organic materials, and a number of elements emitted as particles and vapors. The potential environmental impact of each emission species after passing through state-of-the-art controls was individually assessed using a calculated quantity known as the ambient source severity. This quantity is the ratio of the maximum ground level concentration, as determined through dispersion equations, to an ambient environmental goal. No species was found to have an ambient source severity greater than 1.0; nitrogen oxides (0.97) and sulfur oxides (0.93) had the highest severities. It was estimated that the human population around an average source in this category exposed to an ambient severity greater than 0.05 was $\sim$300,000 persons for nitrogen oxides and sulfur oxides.

Pollutant concentrations were also determined in wastewater and solid waste streams. Effluent source severities, defined as the ratio of the concentration of a pollutant in the receiving water after dilution to an ambient environmental goal, were found to be significantly less than 1.0 for most species. The potential impact of solid waste discharges on the quality of air and of ground and surface water was also found to be minor when available controls are applied.

This report, submitted under Contract No. 68-02-1874 by Monsanto Research Corporation under the sponsorship of the U.S. Environmental Protection Agency, covers the period from May 1974 to August 1980.

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ABBREVIATIONS AND SYMBOLS

a...f -- constants used in dispersion equations
A -- ash percent of coal
AA -- atomic absorption
A...F -- atmospheric stability classes
A_a -- area containing the affected population, km^2
AAQS -- ambient air quality standard
A_R -- ratio $Q/ac\pi u$
ASTM -- American Soceity for Testing and Materials
BOD -- biological oxygen demand
B_R -- ratio $-H^2/2c^2$
$C_{1,2...n}$ -- organic molecules containing from 1 to n carbon atoms
CC -- centrifugal collector
C_D -- concentration of a pollutant in an effluent, g/m^3
COD -- chemical oxygen demand
D_p -- population density, persons/km^2
e -- 2.72
EF -- emission factor, g/kg
ESP -- electrostatic precipitator
exp -- exponent of e
F -- ambient environmental goal, g/m^3
F_e -- effluent hazard factor, g/m^3
FF -- fabric filter
FGD -- flue gas desulfurization
F_{MZ} -- fraction of river flow in a mixing zone
GC-MS -- gas chromatography-mass spectroscopy
H -- height of emission release, m
ICAP -- inductively coupled argon plasma
LC_{50}(96-hr) -- concentration lethal to 50% of a group of test organisms in a 96-hr period, g/m^3
NEDS -- National Emissions Data System
NPDES -- National Pollutant Discharge Elimination System
NSPS -- new source performance standards
OPEC -- oil producing and exporting countries
P' -- total affected population
PCB -- polychlorinated biphenyls
pH -- negative log of the hydrogen ion concentration
POM -- polycyclic organic materials
ppm -- parts per million
Q -- emission rate, g/s
R -- rate of fuel flow
S -- percent of sulfur content of coal

ABBREVIATIONS AND SYMBOLS (continued)

S_a -- ambient severity of air pollutant emissions
S_{AMZ} -- effluent severity after the mixing zone
SASS -- source assessment sampling system
S_{BD} -- effluent severity before dilution
S_e -- ambient severity of an effluent species
S_{MZ} -- effluent severity in the mixing zone
t -- averaging time, min
t_o -- short-term averaging time (3 min)
T.C. -- thermocouple
TDS -- total dissolved solids, g/m³
TLV -- threshold limit value, g/m³
TS -- total solids, g/m³
TSS -- total suspended solids, g/m³
$\underline{u}$ -- wind speed, m/s
$\bar{u}$ -- average wind speed, m/s
USGS -- United States Geological Survey
v_r -- river flow rate, m³/s
V_R -- minimum river flow rate, m³/s
WS -- wet scrubber
x -- downwind emission dispersion distance from source of emission release, m
XAD-2 -- resin used for trapping organic emissions
y -- horizontal distance from centerline of dispersion, m
π -- 3.14
σ_y -- standard deviation of horizontal dispersion, m
σ_z -- standard deviation of vertical dispersion, m
$\bar{\chi}$ -- time-averaged ground level concentration of an emission, g/m³
χ_{max} -- instantaneous maximum ground level concentration, g/m³
$\bar{\chi}_{max}$ -- time-averaged maximum ground level concentration, g/m³

SECTION 1

INTRODUCTION

The purpose of this study was to characterize air emissions, water effluents, and solid residues resulting from the combustion of pulverized bituminous coal in dry botton utility boilers. The report contains a source description that defines process operations, process chemistry, plant capacity, and source locations. The multimedia emissions characterization identifies all emission points and emission species, determines their emission rates, and evaluates the potential environmental effect due to their release. Present and emerging control technologies are also considered. The final section of the report discusses the growth and nature of the source type.

A general indication of the size and position of this source type within all combustion sources is shown in Figures 1 through 3 [1, 2]. From Figure 1, utility combustion is the third largest consumer of fossil fuel, representing 25% of national fossil fuel consumption. Within the utility boiler sector, coal is the largest energy source, representing 59% of utility fuel consumption. All three coals (anthracite, bituminous, and lignite) are used in utility boilers, but bituminous is the primary fuel (97%). Within bituminous coal-fired utility boilers, pulverized dry bottom units represent 72% of all fuel consumption, followed in order of decreasing fuel consumption by pulverized wet bottom units, cyclones, and stokers. Overall this source type consumes 42% of the fossil fuel used in utility boilers and 11% of the total quantity of fossil fuels used for the generation of power or heat in the United States [1,2].

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[1] Annual Report to Congress 1978, Volume II: Data. DOE/EIA-0173/2, U.S. Department of Energy, Energy Information Administration, Washington, D.C., 1978. 202 pp.

[2] Surprenant, N., R. Hall, S. Slater, T. Susa, M. Sussman, and C. Young. Preliminary Environmental Assessment of Conventional Stationary Combustion Systems; Volume II, Final Report. EPA-600/2-76-046b (PB 252 175), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, March 1976. 557 pp.

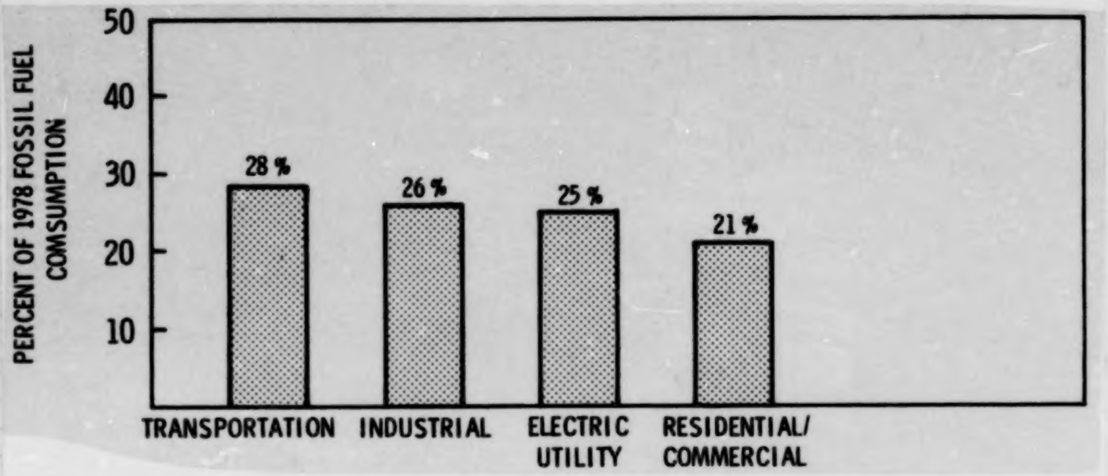

Figure 1. Distribution of total fossil fuel consumption in 1978 by end use [1].

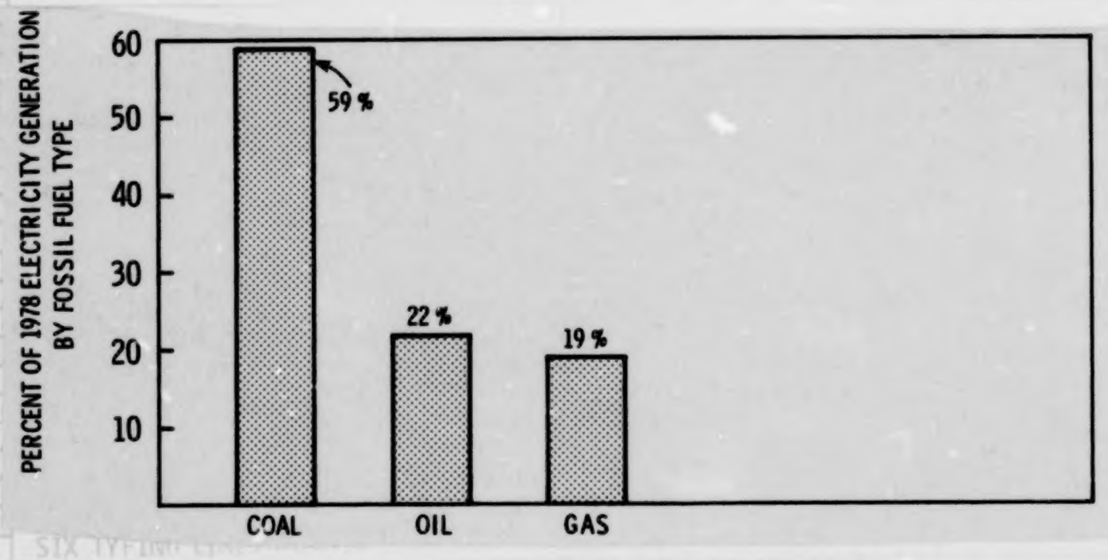

Figure 2. Distribution of fossil fuels used to generate electricity in 1978 [1].

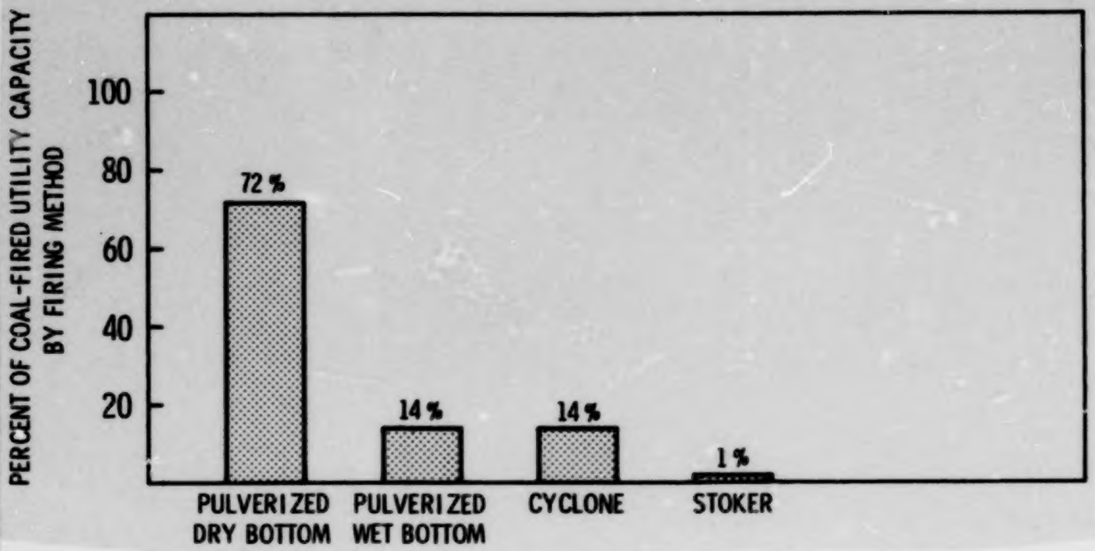

Figure 3. Distribution of coal-fired electric utility capacity according to coal firing method, 1974 [2].

SECTION 2

SUMMARY

This document characterizes and assesses the potential impact of air emissions, wastewater effluents, and solid residues released to the environment by dry bottom utility boilers firing pulverized bituminous coal. This source is defined as all boilers (steam generators) that meet each of the following criteria:

- The primary fuel is pulverized bituminous coal.
- The operating temperature of the furnace is kept below the ash fusion temperature so that ash remaining in the furnace can be removed as a dry powder (dry bottom).
- The boiler is owned and operated by the utility sector to produce steam for electricity generation.

In 1978, this source category consumed an estimated 3.2×10^8 metric tons[a] of bituminous coal and represented 59% of the total U.S. steam electric generating capacity and 72% of utility coal combustion. States containing ≥5% of the boiler population or fuel consumption are listed in Table 1. Capacities of the individual boilers considered in this assessment range from <10 GJ/hr to 7,400 GJ/hr and average 300 GJ/hr.

Over 99% of the air emissions result from coal combustion in the furnace and are emitted from the boiler stack. Other emissions arise from coal storage and handling, cooling towers when used, and ash handling and disposal. Major emissions are the criteria pollutants: particulate matter, sulfur oxides (SO_x), nitrogen oxides (NO_x), hydrocarbons, and carbon monoxide (CO). Polycyclic organic materials (POM) are among the hydrocarbon species emitted. In addition, trace elements are emitted as part of the particulate matter or in the vapor phase. The percent contribution of this source to the total state and national emission

---

[a] 1 metric ton = 10^6 grams; conversion factors and metric system prefixes are presented at the end of this report.

TABLE 1. STATES CONTAINING ≥5% OF THE TOTAL NUMBER OF BOILERS OR FUEL CONSUMPTION

State	Percentage of boilers	Percentage of fuel consumption
Ohio	12.2	14.1
Pennsylvania	12.1	11.1
Michigan	8.6	7.2
Illinois	7.5	5.2
Indiana	5.9	6.5
Kentucky	5.2	6.0
New York	5.5	1.6
North Carolina	4.9	5.9
Tennessee	3.5	6.1
West Virginia	3.4	7.8
Total	68.8	71.5

burdens of criteria pollutants are shown in Table 2. On both a state and national level, this source type is a major contributor to the emission burdens for SO_x, NO_x, and particulate matter.

Particulate emissions are controlled on approximately 86% of the sources according to the National Emissions Data System (NEDS) file for this source type. Particulate controls applied to these boilers include centrifugal collectors (23% of controls), electrostatic precipitators (58%), fabric filters (<1%), wet scrubbers (2%), and dual controls (17%). Of the dual control systems, 77% are centrifugal collector-electrostatic precipitator combinations, 18% are dual electrostatic precipitators, 4% are wet scrubber-electrostatic precipitator combinations, and 1% are centrifugal collector-wet scrubber combinations.

In order to evaluate the potential environmental effect of air emissions from an average source in this category, an ambient source severity, S_a, was defined as the ratio of the time-averaged maximum ground level concentration ($\overline{\chi}_{max}$) to an appropriate ambient environmental goal (F). The values of $\overline{\chi}_{max}$ were calculated from accepted plume dispersion equations and controlled emission factors. The environmental goal is equal to the primary ambient air quality standard in the case of criteria pollutants (particulate matter, SO_x, NO_x, CO, and hydrocarbons) and to a reduced threshold limit value (TLV®), F = TLV x 8/24 x 1/100, for other pollutants. The factor 8/24 corrects for a 24-hr exposure while 1/100 is a safety factor.

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TABLE 2. PERCENT CONTRIBUTION OF EMISSIONS FROM DRY BOTTOM UTILITY BOILERS FIRING PULVERIZED BITUMINOUS COAL TO TOTAL STATE AND NATIONAL EMISSIONS OF CRITERIA POLLUTANTS FROM STATIONARY SOURCES

	Percent of total emissions burden				
State	Particulate matter	SO_x	NO_x	Hydrocarbons	CO
Alabama	30.3	60.8	60.3	2.1	0.4
Alaska	11.0	0.9	4.5	0.1	0.6
Arizona	5.4	2.6	5.6	0.1	0.1
Colorado	1.8	30.9	31.8	0.8	0.2
Delaware	2.3	26.8	16.7	0.2	0.4
Florida	3.8	35.6	14.3	0.3	0.1
Georgia	14.2	69.4	36.8	0.8	1.0
Illinois	14.7	49.5	20.7	0.3	0.1
Indiana	8.3	54.0	32.3	0.8	<0.1
Iowa	3.8	45.7	16.6	0.7	3.4
Kansas	0.6	23.5	4.7	<0.1	0.3
Kentucky	25.2	74.8	50.3	1.5	0.7
Maryland	8.6	30.6	19.9	0.4	<0.1
Massachusetts	3.0	3.9	2.0	<0.1	0.5
Michigan	14.1	63.7	34.8	0.9	0.2
Minnesota	3.4	25.5	17.3	0.3	0.1
Mississippi	2.3	44.8	12.3	0.1	0.3
Missouri	0.6	23.3	12.4	0.2	1.0
Montana	0.2	11.7	10.6	0.1	0.2
Nebraska	1.8	27.3	14.5	0.2	1.2
Nevada	0.6	1.1	13.2	0.7	2.1
New Jersey	3.1	11.8	4.8	<0.1	0.6
New Mexico	21.5	38.9	42.0	0.5	8.4
New York	2.3	17.2	16.7	0.3	0.1
North Carolina	19.0	50.6	43.0	1.1	3.0
Ohio	30.9	70.3	40.6	1.0	0.1
Oklahoma	<0.1	<0.1	<0.1	<0.1	<0.1
Pennsylvania	12.3	50.6	37.3	0.7	0.1
South Carolina	6.5	12.2	48.8	0.1	0.1
Tennessee	37.0	73.1	45.4	1.6	4.5
Texas	0.4	3.5	3.1	<0.1	0.1
Utah	7.5	23.5	35.2	0.7	0.1
Virginia	25.5	16.4	19.8	0.3	1.0
Washington	0.1	3.0	25.2	0.3	0.6
West Virginia	17.4	58.1	56.6	2.4	0.5
Wisconsin	18.5	47.6	28.8	0.5	2.9
Wyoming	23.3	31.5	47.2	1.0	11.1
United States	9.3	44.5	25.6	0.4	0.2

Controlled emission factors and ambient source severities were calculated for an average size unit in this category. The average boiler was determined to fire coal having an ash content of 12.6% and a sulfur content of 2.08% at a rate of 11 kg/s. Flue gases are discharged into the atmosphere from a stack 92.6 m high with a plume rise of 59 m. Ambient severities from this average source are given in Table 3 and show that the highest values are for SO_x (0.93) and NO_x (0.97).

Another measure of potential environmental impact is the population which may be affected by emissions from an average source. The affected population is defined as the number of persons living in the area around an average size boiler where $\overline{\chi}$ (time-averaged ground level concentration) divided by F is greater than 1.0 or greater than 0.05. A $\overline{\chi}/F$ value of 1.0 indicates exposure to a concentration of a pollutant greater than the environmental goal; the value of 0.05 allows for inherent uncertainties in measurement techniques, dispersion modeling, and health effects data. Plume dispersion equations are used to find this area, which is then multiplied by an average population density to determine the affected population. The average population around a utility boiler in this category is estimated to be 470 persons/km^2. The populations affected by emissions having $\overline{\chi}/F$ greater than 0.05 are also shown in Table 3.

Water usage in utility boiler operations is highly variable. Waste streams common to most boilers in this category are boiler blowdown, wastes from feedwater treatment, and equipment cleaning wastes. Other waste streams which may or may not be present, depending on the boiler size, location, and application, are once-through cooling water for steam condensation and equipment cooling, recirculating cooling water blowdown, water from ash ponds, runoff from coal storage piles, and effluent from SO_2 removal systems.

The potential impact of wastewater discharges was determined in a manner analogous to that used for air emissions. Effluent source severity, S_e, was defined as the ratio of the dispersed concentration of a pollutant in the receiving water to an effluent environmental goal. Water quality criterion values were used for environmental goals if available. If not, then $0.1[LC_{50}(96\text{-hr})]$ was used, for the aquatic species most sensitive to the pollutant of concern. An average receiving body for this source was determined to have a flow rate of 1.29×10^8 m^3/d. Effluent severities were found to be less than 1.0 for all pollutants from all discharge streams, and in almost all cases were below 0.01.

Solid wastes generated at coal-fired power plants consist of coal ash, SO_x scrubber sludge, and water treatment sludges. Of these, coal ash is the primary waste (>99%), although SO_x scrubber sludges will become a major waste as more stringent SO_2 regulations are implemented. The environmental impact of solid wastes

TABLE 3. CONTROLLED EMISSION FACTORS, SOURCE SEVERITIES, AND AFFECTED POPULATIONS FOR THE AVERAGE DRY BOTTOM UTILITY BOILER FIRING PULVERIZED BITUMINOUS COAL

Emission species	Controlled emission factor, g/kg of coal	Ambient source severity	Affected population for $S_a > 0.05$, persons
Particulate matter	$0.21A$[a]	9.0×10^{-2}	19,000
NO_x	10[b]	9.7×10^{-1}	300,000
SO_x	$19S$[b,c]	9.3×10^{-1}	320,000
CO	0.5	1.9×10^{-4}	
Hydrocarbons	0.1	7.8×10^{-3}	0
POM (total)	1.6×10^{-5}	2.2×10^{-4}	0
POM (carcinogenic)	4.0×10^{-6}	1.0×10^{-2}	0
Elements:			
Aluminum	1.8×10^{-1}	4.9×10^{-2}	0
Antimony	1.2×10^{-3}	6.3×10^{-3}	0
Arsenic	2.6×10^{-2}	1.4×10^{-1}	36,000
Barium	1.0×10^{-3}	5.2×10^{-3}	0
Beryllium	2.1×10^{-5}	2.8×10^{-2}	0
Bismuth	$<1.0 \times 10^{-6}$	$<2.6 \times 10^{-7}$	0
Boron	2.9×10^{-2}	7.5×10^{-3}	0
Bromine	1.1×10^{-2}	4.1×10^{-2}	0
Cadmium	6.8×10^{-4}	3.6×10^{-2}	0
Calcium	1.3×10^{-2}	6.7×10^{-3}	0
Cerium	1.4×10^{-4}	3.7×10^{-5}	0
Cesium	2.5×10^{-4}	3.3×10^{-4}	0
Chlorine	7.3×10^{-1}	2.8×10^{-1}	82,000
Chromium	2.0×10^{-3}	5.2×10^{-2}	5,500
Cobalt	6.8×10^{-5}	1.8×10^{-3}	0
Copper	2.2×10^{-2}	6.0×10^{-2}	7,700
Dysprosium	1.4×10^{-5}	3.7×10^{-6}	0
Erbium	2.6×10^{-6}	6.7×10^{-7}	0
Europium	5.9×10^{-6}	1.6×10^{-6}	0
Fluorine	7.8×10^{-2}	1.0×10^{-1}	24,000
Gadolinium	1.0×10^{-5}	2.6×10^{-6}	0
Gallium	6.5×10^{-3}	1.7×10^{-3}	0
Germanium	$<4.8 \times 10^{-3}$	$<1.3 \times 10^{-3}$	0
Gold	$<1.0 \times 10^{-6}$	$<2.6 \times 10^{-7}$	0
Hafnium	1.2×10^{-5}	6.3×10^{-5}	0
Holmium	2.1×10^{-6}	5.6×10^{-6}	0
Iodine	1.1×10^{-3}	2.9×10^{-3}	0
Iridium	$<2.0 \times 10^{-6}$	$<5.2 \times 10^{-7}$	0
Iron	1.9×10^{-1}	1.0×10^{-1}	23,000
Lanthanum	9.3×10^{-5}	2.5×10^{-5}	0
Lead	1.5×10^{-2}	2.6×10^{-1}	81,000
Lithium	2.7×10^{-4}	7.1×10^{-5}	0
Lutetium	1.2×10^{-6}	3.2×10^{-7}	0
Magnesium	6.9×10^{-3}	1.8×10^{-3}	0

(continued)

TABLE 3 (continued)

Emission species	Controlled emission factor, g/kg of coal	Ambient source severity	Affected population for $S_a > 0.05$, persons
Elements:			
Manganese	5.9×10^{-3}	3.1×10^{-3}	0
Mercury	2.4×10^{-4}	1.3×10^{-2}	0
Molybdenum	3.1×10^{-3}	1.6×10^{-2}	0
Neodymium	1.2×10^{-4}	3.2×10^{-5}	0
Nickel	1.5×10^{-3}	4.1×10^{-2}	
Niobium	5.4×10^{-5}	1.4×10^{-5}	0
Osmium	$<2.0 \times 10^{-4}$	$<2.6 \times 10^{-1}$	78,000
Palladium	$<1.0 \times 10^{-6}$	$<2.6 \times 10^{-7}$	0
Phosphorus	9.2×10^{-2}	2.4×10^{-1}	70,000
Platinum	$<3.0 \times 10^{-6}$	$<4.1 \times 10^{-3}$	0
Potassium	2.3×10^{-2}	3.0×10^{-2}	0
Praeseodymium	2.1×10^{-5}	5.6×10^{-6}	0
Rhenium	$<2.0 \times 10^{-4}$	$<5.2 \times 10^{-5}$	0
Rhodium	$<1.0 \times 10^{-6}$	$<2.6 \times 10^{-5}$	0
Rubidium	3.7×10^{-4}	9.7×10^{-5}	0
Ruthenium	$<1.0 \times 10^{-6}$	$<2.6 \times 10^{-7}$	0
Samarium	1.9×10^{-5}	4.9×10^{-6}	0
Scandium	5.1×10^{-5}	1.3×10^{-5}	0
Seleniun	4.5×10^{-3}	6.0×10^{-2}	
Silicon	2.7×10^{-1}	7.1×10^{-2}	8,600
Silver	2.5×10^{-5}	6.7×10^{-3}	13,000
Sodium	3.3×10^{-3}	4.1×10^{-3}	0
Strontium	1.0×10^{-3}	2.6×10^{-4}	0
Tantalum	9.5×10^{-6}	4.9×10^{-6}	0
Tellurium	3.4×10^{-4}	9.0×10^{-3}	0
Terbium	3.2×10^{-6}	8.6×10^{-7}	0
Thallium	1.0×10^{-4}	2.6×10^{-3}	0
Thorium	4.8×10^{-5}	1.3×10^{-5}	0
Thulium	$<1.0 \times 10^{-6}$	$<2.6 \times 10^{-7}$	0
Tin	2.4×10^{-5}	6.3×10^{-6}	0
Titanium	8.1×10^{-3}	2.1×10^{-3}	0
Tungsten	2.8×10^{-4}	7.5×10^{-4}	0
Uranium	1.4×10^{-4}	1.8×10^{-3}	0
Vanadium	2.0×10^{-3}	1.0×10^{-2}	0
Ytterbium	9.8×10^{-6}	2.6×10^{-6}	0
Yttrium	1.1×10^{-4}	2.9×10^{-4}	0
Zinc	1.8×10^{-2}	9.3×10^{-3}	0
Zirconium	5.0×10^{-4}	2.6×10^{-4}	0

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[a] Percent ash content of coal.

[b] Uncontrolled.

[c] Percent sulfur content of coal.

from this source type is dependent on the disposal method used and the characteristics of the disposal site, which are variable.

Coal consumption by boilers covered in this assessment is expected to increase because of the growing demand for energy and the shortage of alternate fuel supplies (i.e., natural gas and oil). Total utility coal consumption is forecast to increase from 4.30×10^8 metric tons in 1978 to over 7.25×10^8 metric tons in 1985 and to over 1.36×10^9 metric tons by the year 2000.

SECTION 3

SOURCE DESCRIPTION

The source type covered in this assessment is entitled dry bottom utility boilers firing pulverized bituminous coal. This section defines the source type, characterizes the United States population of the source, and describes the processes of steam generation and combustion as they relate to the source. A parallel report covering dry bottom industrial boilers firing pulverized bituminous coal has already been published [3].

SOURCE DEFINITION

For the purposes of this study, dry bottom utility boilers firing pulverized bituminous coal are defined as all boilers (steam generators) which meet each of the following criteria:

- The primary fuel is pulverized bituminous coal.
- The operating temperature of the furnace is kept below the ash fusion temperature so that ash remaining in the furnace can be removed as a dry powder (hence the term dry bottom).
- The boiler is owned and operated by the utility sector to produce steam for electricity generation.

Bituminous coals include both bituminous and subbituminous coals as defined by the American Society for Testing and Materials [4]. Both coal types are considered together because the source of coal production and consumption data utilized in this report generally reports both types as bituminous coal.

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[3] McCurley, W. R., C. M. Moscowitz, J. C. Ochsner, and R. B. Reznik. Source Assessment: Dry Bottom Industrial Boilers Firing Pulverized Bituminous Coal. EPA-600/2-79-019e, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, June 1979. 199 pp.

[4] Standard Specification for Classification of Coals by Rank, Designation D 388-66 (Reapproved 1972). In: 1976 Annual Book of ASTM Standards, Part 26: Gaseous Fuels; Coal and Coke; Atmospheric Analysis. American Society for Testing and Materials, Philadelphia, Pennsylvania, 1976. pp. 211-214.

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In a pulverized coal system, coal is pulverized into a fine powder, 70% of which will pass through a 200-mesh screen. Pulverizing coal facilitates injection into the boiler and mixture with combustion air for better combustion. For systems of this type, secondary fuels such as natural gas or fuel oil are often used during start-up to maintain stable ignition until operating temperatures are reached.

The word "boiler" refers, in a strict sense, to the pressure vessel in which water is heated and/or converted to steam. In this study, the term is used to denote a complete system including all of the process operations and onsite facilities involved in the operation of dry bottom utility boilers firing pulverized bituminous coal, with one exception. Coal storage piles have already been assessed as an emission source [5] and therefore are not considered here. Support facilities and operations addressed in this source assessment include: boiler feedwater treatment, fuel and ash conveying, air and water pollution control, and solid waste disposal.

SOURCE INVENTORY

A complete national inventory of dry bottom utility boilers firing pulverized bituminous coal can be obtained from the National Emission Data System (NEDS). A recent point source listing gave a population for this source type of 902 boilers[a] [6]. This value is higher than some previous estimates which are based on older data, because the number of boilers in this source type is increasing. By way of example, GCA/Technology Division estimated a pulverized dry bottom utility boiler population of 594 boilers and a corresponding capacity of 91,480 MW. The total capacity for all coal-fired utility boilers was given as 139,420 MW [2]. These values were based on 1972 data from the Federal Power Commission (FPC). However, a 1977 report from the FPC reported

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[a] The actual printout showed 955 sources but checking revealed 53 boilers that were either not utility boilers, no longer in operation, or converted to oil firing.

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[5] Blackwood, T. R., and R. A. Wachter. Source Assessment: Coal Storage Piles. EPA-600/2-78-004k (PB 284 297), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, May 1978. 98 pp.

[6] NEDS Condensed Point Source Listing for Particulate for All Values Greater Than or Equal to 100 Short Tons of Emissions Per Year: SCC 1-01-002-02, SCC 1-01-002-07, SCC 1-01-002-12. Generated by U.S. Environmental Protection Agency, Durham, North Carolina, March 2, 1978.

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the total capacity for all coal-fired power plants at 213,592 MW (a 53% increase), and the listing of individual boilers corresponded very closely to the NEDS listing [7].

Reported coal consumption in 1978 for all coal-fired utility boilers was 4.4×10^8 metric tons [1]. Since dry bottom pulverized units represent 72% of coal-fired capacity [2], the estimated 1978 coal consumption for this source type is 3.2×10^8 metric tons. This value compares favorably with the total coal consumption reported in NEDS of 2.8×10^8 metric tons [6], based on slightly older data.

AVERAGE BOILER PARAMETERS

An average boiler size was calculated from the estimated 1978 coal consumption of 3.2×10^8 metric tons and the NEDS population of 902 dry bottom pulverized bituminous utility boilers. The most recent coal consumption data were chosen for calculation purposes because of the trend toward building larger size utility boilers. The average boiler thus burns 3.55×10^5 metric tons of coal per year or 11 kg/s. Average generating capacity, based on 1977 FPC data and the estimated 72% of total coal-fired capacity for dry bottom pulverized units, is 160 MW.

Based on NEDS data [6], the average stack height is 92.6 m. Average coal characteristics are: ash content, 12.6%; sulfur content, 2.08%; and heating value, 27.2 MJ/kg.

The geographical distribution of dry bottom utility boilers firing pulverized bituminous coal according to fuel usage and boiler population as obtained from NEDS [6] is shown in Table 4. Utility boilers are concentrated in the major industrial states, and they tend to be located in larger cities and along major waterways. The states of Ohio, Pennsylvania, Indiana, Illinois, Michigan, and New York account for 52% of the boiler population and 46% of the fuel consumption.

STEAM PRODUCTION PROCESS

A simplified process schematic of a dry bottom utility boiler firing pulverized bituminous coal is presented in Figure 4. In general, coal is pulverized, mixed with primary combustion air, and fed to a burner. Secondary combustion air is introduced via the burner, and the resulting mixture is injected into the furnace where it is ignited and burned. Heat generated by combustion is transferred to boiler feedwater through tubes that make

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[7] Inventory of Power Plants in the United States. DOE/RA-0001, U.S. Department of Energy, Washington, D.C., December 1977. 451 pp.

TABLE 4. GEOGRAPHICAL DISTRIBUTION OF COAL-FIRED DRY BOTTOM UTILITY BOILERS [6]

State	Percent of source population	Percent of fuel consumption
Alabama	2.2	4.0
Alaska	0.1	<0.1
Arizona	0.1	0.1
Colorado	2.0	1.4
Delaware	0.3	0.3
District of Columbia	0.2	<0.1
Florida	1.6	1.6
Georgia	3.1	4.6
Illinois	7.5	5.2
Indiana	5.9	6.5
Iowa	2.8	0.9
Kansas	0.7	0.2
Kentucky	5.2	6.0
Maryland	1.1	1.4
Massachusetts	0.2	<0.1
Michigan	8.6	7.2
Minnesota	1.9	1.0
Mississippi	0.3	0.4
Missouri	1.2	0.8
Montana	0.1	0.2
Nebraska	1.4	0.3
Nevada	0.2	0.2
New Jersey	0.8	0.4
New Mexico	0.7	1.1
New York	5.5	1.6
North Carolina	4.9	5.9
Ohio	12.2	14.1
Oklahoma	0.3	<0.1
Pennsylvania	12.1	11.1
South Carolina	1.3	0.3
Tennessee	3.5	6.1
Texas	0.2	1.2
Utah	1.1	0.6
Virginia	1.0	1.3
Washington	0.2	1.3
West Virginia	3.4	7.8
Wisconsin	4.5	2.5
Wyoming	1.2	2.1

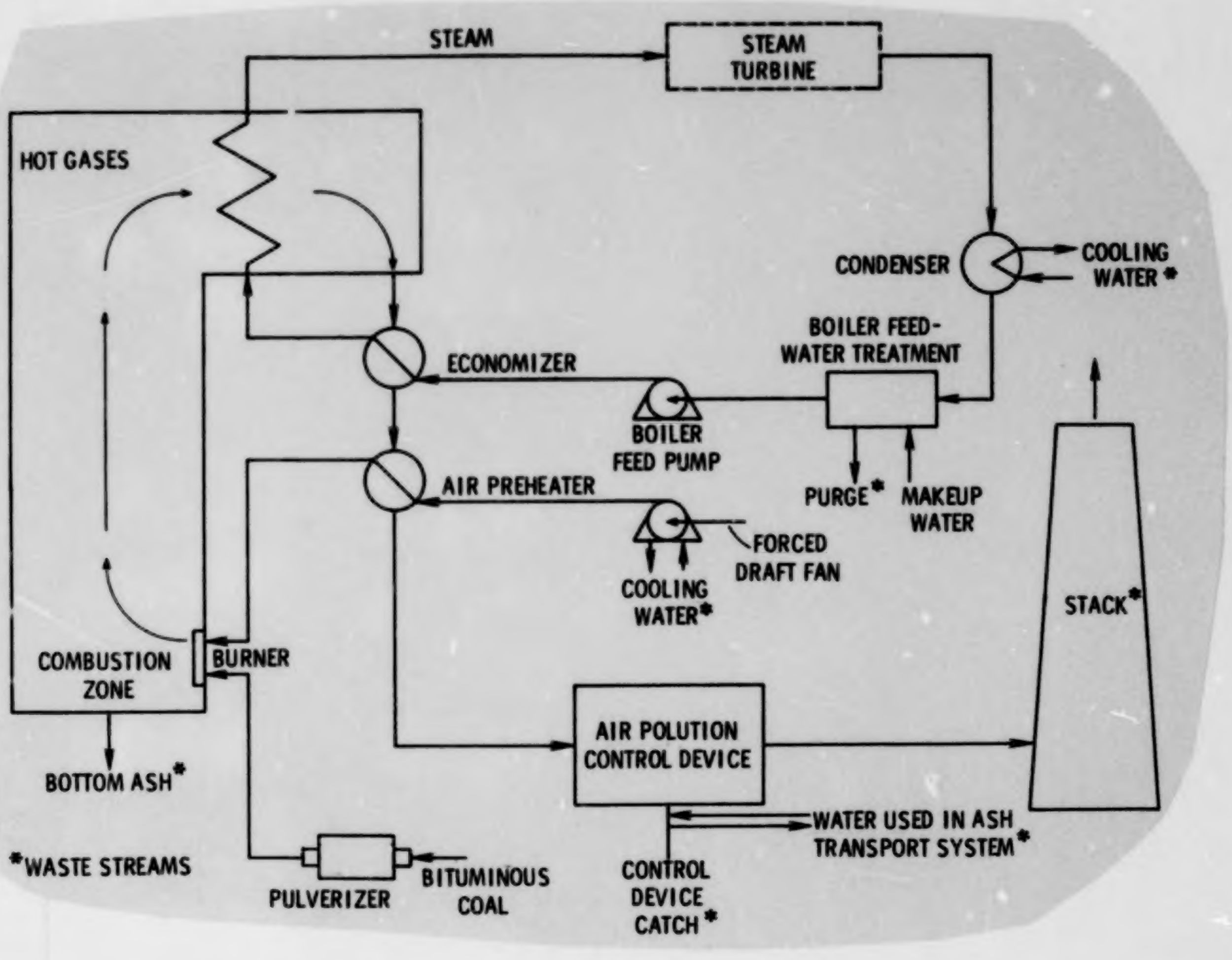
STEAM
STEAM TURBINE
HOT GASES
CONDENSER
COOLING WATER *
BOILER FEED-WATER TREATMENT
ECONOMIZER
BOILER FEED PUMP
PURGE*
MAKEUP WATER
AIR PREHEATER
FORCED DRAFT FAN
COOLING WATER*
STACK*
COMBUSTION ZONE
BURNER
AIR POLUTION CONTROL DEVICE
BOTTOM ASH*
WATER USED IN ASH TRANSPORT SYSTEM*
*WASTE STREAMS
PULVERIZER
BITUMINOUS COAL
CONTROL DEVICE CATCH *

Figure 4. Simplified process schematic for a pulverized bituminous coal-fired utility boiler.

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up the furnace walls. Steam is removed from the boiler tubes and passed through turbines to generate electricity. Heat is further extracted from the flue gases after they leave the furnace and used to raise the temperature of the steam, boiler feedwater, and/or combustion air. Combustion gases are treated to reduce pollution and then exhausted to the atmosphere.

A more detailed description of the unit operations and equipment involved in steam generation follows, except for emissions/effluent control and ash disposal, which are discussed later in the report. The following description is only an overview because numerous references have been published with the sole purpose of examining combustion and combustion equipment [8-14].

At power plant sites, coal is fed from storage piles to bunkers that supply the pulverizers. In a pulverizer, coal is reduced in size by impact, attrition, and crushing to the desired degree of fineness. Commonly used grinding mechanisms include ball and race mills, roll and race mills, ball (tube) mills, and impact (hammer) mills.

Pulverizing serves to increase the surface area that can be directly exposed to oxygen thereby increasing the rate of the primary combustion reactions. This results in decreased combustion time, increased throughput of coal, and increased heat output. Coal is pulverized to the extent that 70% will pass a 200-mesh screen. Larger particles may be separated from the coal-air stream by a cyclone and returned to the pulverizer.

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[8] Steam/Its Generation and Use, 38th Edition. Babcock & Wilcox, New York, New York, 1972.

[9] Edwards, J. B. Combustion: The Formation and Emission of Trace Species. Ann Arbor Science Publishers, Inc., Ann Arbor, Michigan, 1974. 240 pp.

[10] Combustion-Generated Air Pollution, E. E. Starkman, ed. Plenum Press, New York, New York, 1971. 355 pp.

[11] Field, M. A., D. W. Gill, B. B. Morgan, and P. G. W. Hawksley. Combustion of Pulverized Coal. The British Coal Utilization Research Association, Leatherhead, 1967. 413 pp.

[12] Combustion Engineering, A Reference Book on Fuel Burning and Steam Generation, O. de Lorenzi, ed. Combustion Engineering, Inc., New York, New York, 1957. 1025 pp.

[13] Potter, P. J. Steam Power Plants. The Ronald Press Company, New York, New York, 1949. 503 pp.

[14] Shields, C. D. Boilers - Types, Characteristics, and Functions. FW Dodge Corporation, New York, New York, 1961. 559 pp.

During pulverizing, the coal is dried by a stream of hot air that may be either forced or induced through the unit. Air is heated prior to entering the pulverizer by an air heater (boiler waste heat recovery unit) or by an auxiliary heater. The air flow through the pulverizer is additionally responsible for entraining and thus transporting the crushed coal to a storage vessel (indirect feed) or to the burners (direct feed) where it becomes the primary combustion air. Finely divided coal is explosive in nature; thus, direct feed systems are generally preferred for safety reasons, even though indirect feed systems require less energy.

Pulverizers used in direct feed systems have automatic controls to adjust the coal and air flow rates to compensate for variations in boiler load. Boiler loads from 40% to 60% of capacity can be obtained by adjusting the fuel and air flow rates to the burners. Firing at loads less than 40% requires that burners and possibly pulverizers be taken out of service.

A burner receives the primary air-coal mixture, dilutes it with secondary air, and injects it into the furnace. Burners are designed to promote stability of ignition, completeness of combustion, uniform distribution of temperature and excess air leaving the furnace, and freedom from localized slag deposits. These objectives are partially met through the creation of turbulence and effective adjustment of the ignition point and flame shape. A secondary function of some burners is to fire another fuel concurrently with pulverized coal in order to sustain ignition during start up and periods of low load.

Burners designed to handle pulverized coal are generally classified according to their firing geometry. Figure 5 [15] illustrates the three basic orientations; i.e., vertical, horizontal, and tangential.

One of the products of coal combustion is an inorganic ash formed from minerals in the coal. A portion of the ash, referred to as fly ash, is entrained in the hot combustion gases that exit the furnace. The remainder of the ash settles to the bottom of the furnace in the combustion zone and is called bottom ash. Because of air pollution regulations, fly ash is normally removed from the flue gas before it is emitted to the atmosphere.

The production of high-pressure steam involves the transfer of the heat of combustion to the boiler feedwater by radiation and convection. In order to obtain the highest thermal efficiency, as much of the heat of combustion as possible must be transferred

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[15] Chemical Engineers' Handbook, Fifth Edition, J. H. Perry and C. H. Chilton, eds. McGraw-Hill Book Company, New York, New York, 1973.

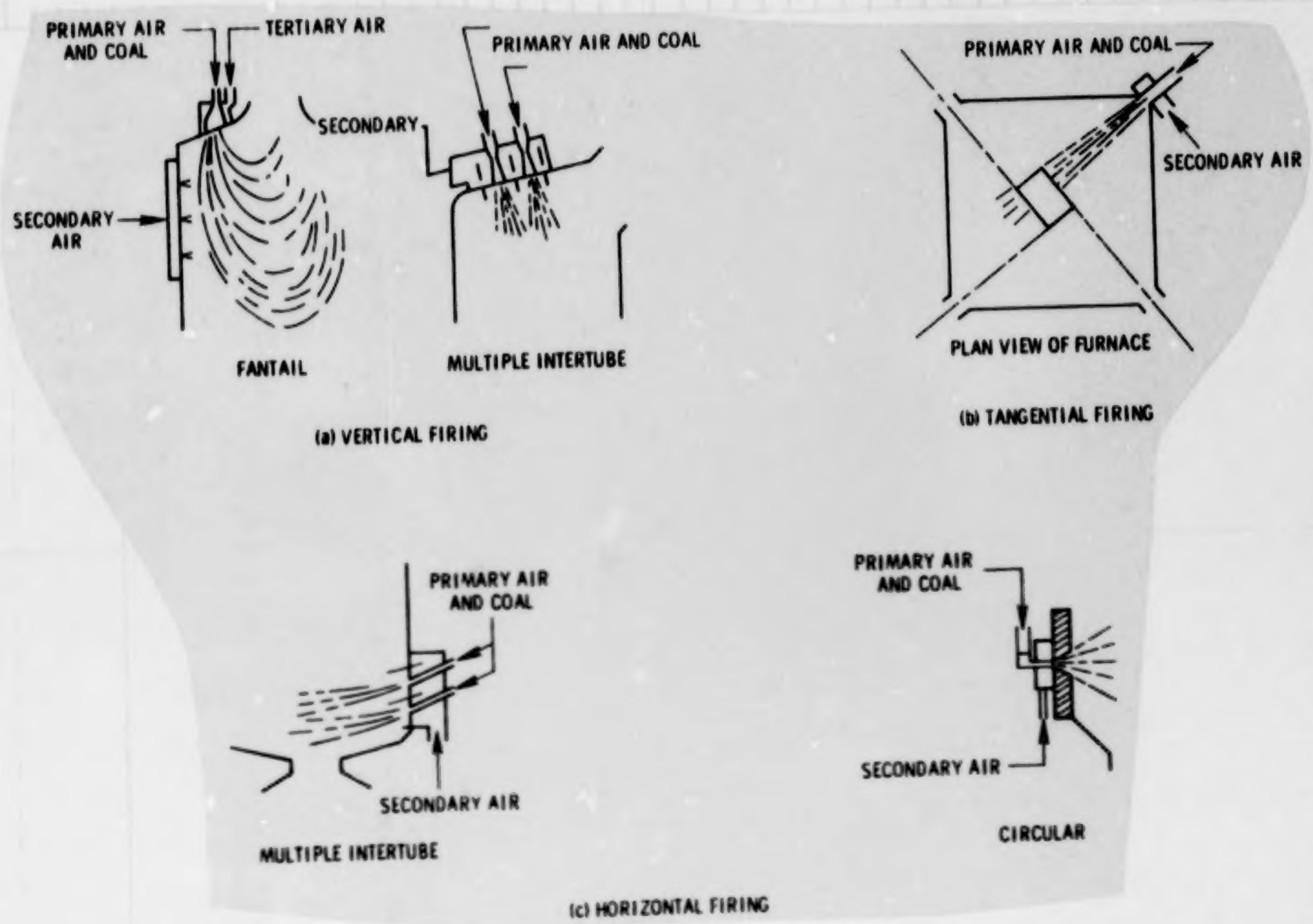
PRIMARY AIR AND COAL
TERTIARY AIR
SECONDARY AIR
SECONDARY
FANTAIL
PRIMARY AIR AND COAL
MULTIPLE INTERTUBE
(a) VERTICAL FIRING
PRIMARY AIR AND COAL
SECONDARY AIR
PLAN VIEW OF FURNACE
(b) TANGENTIAL FIRING
PRIMARY AIR AND COAL
SECONDARY AIR
MULTIPLE INTERTUBE
PRIMARY AIR AND COAL
SECONDARY AIR
CIRCULAR
(c) HORIZONTAL FIRING

Figure 5. Various methods of firing pulverized bituminous coal [15].

Reprinted from Chemical Engineers' Handbook, Fifth Edition, J. H. Perry and C. H. Chilton, eds., p. 9-21, by permission of McGraw-Hill Book Company.

from the hot combustion gases and the gases discharged at the lowest possible temperature. Feedwater is introduced into the boiler by the boiler feed pump and first enters a series of tubes (regenerative feedwater heater) near the point where combustion gases exit from the boiler. There it is heated to near the boiling point. The water then flows to one or more drums connected by a number of tubes. The tubes are arranged in vertical rows along the walls (water walls) of the combustion zone of the boiler. In this zone, the water in the tubes is vaporized to saturated steam primarily by the radiant heat of combustion. The saturated steam is then further heated to higher temperatures primarily by convection of the hot gases in the superheater section of the boiler. In some boilers, the steam is reheated after passage through the initial sections of the turbine. Finally, the flue gases are passed through a heat exhanger (air heater) in order to transfer heat at a low temperature to the air being blown into the boiler.

Boiler feedwater is composed of recycled condensed steam and makeup water. Makeup water must be treated prior to use to remove suspended and dissolved solids. A characterization of typical makeup water is presented in Table 5 [16]. Concentrations of the listed species in boiler water can result in reduced efficiency and eventually in boiler tube failure. Specific problems caused by these materials are summarized in Table 6 [17].

TABLE 5. TYPICAL CHARACTERISTICS OF BOILER WATER SUPPLIES [16]

Constituent	Concentration, g/m^3
Calcium, as $CaCO_3$	40 to 200
Magnesium, as $CaCO_3$	10 to 50
Alkalinity, as $CaCO_3$	5 to 50
Sulfate, as $SO_4^{=}$	20 to 140
Chloride, as Cl^-	10 to 150
Silica, as SiO_2	2 to 15
Iron, as Fe	0.2 to 2.0
Manganese, as Mn	0.1 to 1.0
Oil	<1 to 5.0
Suspended solids	10 to 200
pH	5.5 to 7.5

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[16] Nichols, C. R. Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source Category. EPA-440/1-74-029-A (PB 240 853), U.S. Environmental Protection Agency, Washington, D.C., Ocotber 1974. 865 pp.

[17] Betz Handbook of Industrial Water Conditioning. Betz Laboratories, Inc., Trevose, Pennsylvania, 1976. pp 18-19.

TABLE 6. WATER IMPURITIES, PROBLEMS, AND TREATMENT [17]

Reprinted from Betz Handbook of Industrial Water Conditioning, pp 18-19, by permission of Betz Laboratories, Inc., Trevose, Pennsylvania.

Constituent	Difficulties caused	Means of treatment
Turbidity	Deposits in water lines, process equipment, boilers, etc.	Coagulation, settling and filtration.
Color	May cause foaming in boilers. Hinders precipitation methods such as iron removal and softening.	Coagulation and filtration. Chlorination. Adsorption by activated carbon.
Hardness	Chief source of scale in heat exchange equipment, boilers, pipe lines, etc.	Softening. Demineralization. Internal boiler water treatment. Surface active agents.
Alkalinity	Foaming and carryover of solids with steam. Embrittlement of boiler steel. Bicarbonate and carbonate produce CO_2 in steam, a source of corrosion in condensate lines.	Lime and lime-soda softening. Acid treatment. Hydrogen zeolite softening. Demineralization. Dealkalization by anion exchange.
Free mineral acid	Corrosion.	Neutralization with alkalies.
Carbon dioxide	Corrosion in water lines and particularly steam and condensate lines.	Aeration. Deaeration. Neutralization with alkalies.
pH	pH varies according to acidic or alkaline solids in water. Most natural waters have a pH of 6-8.	pH can be increased by alkalies and decreased by acids.
Sulfate	Adds to solids content of water, but, in itself, is not usually significant. Combines with calcium to form calcium sulfate scale.	Demineralization.
Chloride	Adds to solids content and increases corrosive character of water.	Demineralization.
Nitrate	Adds to solids content, but is not usually significant industrially. Useful for control of boiler metal embrittlement.	Demineralization.

(continued)

TABLE 6 (continued)

Constituent	Difficulties caused	Means of treatment
Silica	Scale in boilers and cooling water systems. Insoluble turbine blade deposits due to silica vaporization.	Hot process removal with magnesium salts. Adsorption by highly basic anion exchange resins, in conjunction with demineralization.
Iron	Source of deposits in water lines, boilers, etc.	Aeration. Coagulation and filtration. Lime softening. Cation exchange. Contact filtration. Surface active agents for iron retention.
Manganese	Same as iron.	Same as iron.
Oxygen	Corrosion of water lines, heat exchange equipment, boilers, return lines, etc.	Deaeration. Sodium sulfite. Corrosion inhibitors.
Hydrogen sulfide	Corrosion.	Aeration. Chlorination. Highly basic anion exchange.
Ammonia	Corrosion of copper and zinc alloys by formation of complex soluble ion.	Cation exchange with hydrogen zealite. Chlorination. Deaeration.
Dissolved solids	Dissolved solids is measure of total amount of dissolved matter, determined by evaporation. High concentrations of dissolved solids are objectionable because of process interference and as a cause of foaming in boilers.	Various softening processes, such as lime softening and cation exchange by hydrogen zeolite, will reduce dissolved solids. Demineralization.
Suspended solids	Suspended solids is the measure of undissolved matter, determined gravimetrically. Suspended solids plug lines, cause deposits in heat exhcange equipment, boilers, etc.	Subsidence. Filtration, usually preceded by coagulation and settling.
Total solids	Total solids is the sum of dissolved and suspended solids, determined gravimetrically.	See "Dissolved Solids" and "Suspended Solids."

The level of treatment needed to alleviate these problems is a function of both the feedwater composition and the quality of the steam generated (higher temperature, higher pressure steam requires more treatment). Utility boiler feedwaters are commonly treated to remove hardness/dissolved minerals, silica, dissolved oxygen and CO_2. Both external and internal treatment methods are used. In external treatment, the feedwater passes through unit purification processes (e.g., ion exchange or softening) before entering the boiler. Internal treatment involves the addition of chemical agents to the feedwater that act within the boiler. Detailed descriptions of water treatment technology are readily available in the literature [12, 17-19].

As water is converted to steam in the boiler, trace impurities still present, such as dissolved solids, are concentrated in the boiler water. When sufficiently high concentrations are reached, these materials precipitate and coat the inner sides of the heat transfer surfaces. This impairs the transfer of heat in the boiler unit and reduces boiler efficiency. In order to prevent deposition of these materials, a portion of the boiler water is usually drawn off and replaced by feedwater. The blowdown (that portion of the boiler water removed to maintain an acceptable dissolved solids concentration) then becomes a wastewater stream.

The conversion of the pressure energy of the steam into mechanical energy occurs in the steam turbine. In the turbine, the steam flows through a succession of passages made up of blades mounted on alternately moving and stationary discs. As the steam passes from disc to disc, it gives up its energy to the rotating blades and in the process loses pressure and increases in volume. If the steam enters the turbine in a saturated condition, a small portion of the steam will condense as it passes through the turbine. One reason for superheating or reheating steam is to reduce this condensation and the mechanical problems associated with it.

There are many different types of turbines and turbine arrangements in use in steam electric power plants. Almost all turbines in use in central generating plants are of the condensing type, discharging the steam from the last stage at below atmospheric pressure to improve efficiency. In general, turbines designed for once-through cooling systems operate at lower back pressures than those designed for closed cooling systems.

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[18] Industrial Water Treatment Practice, P. Hamer, J. Jackson, and E. F. Thurston, eds. Butterworth and Company, Ltd., London, England, 1961. 514 pp.

[19] Nordell, E. Water Treatment for Industrial and Other Uses, Second Edition. Reinhold Publishing Corp., New York, New York, 1961. 598 pp.

Steam electric power plants use a condenser to maintain a low turbine exhaust pressure by condensing the steam leaving the turbine at a temperature corresponding to vacuum conditions, thus providing a high cycle efficiency and recovering the condensate for return to the cycle. Since cleanliness of the condenser is essential to maintaining maximum heat transfer efficiency, it is common practice to add some type of biocide to the cooling water to control the growth of algae or slimes in the condenser. In spite of these biocides, most power plants also clean condensers mechanically as part of regularly scheduled maintenance procedures.

Operation of the condenser requires large quantities of cooling water. Wherever adequate supplies of cooling water are available, it has been common practice to take cooling water from a natural source, pump it through the condenser, and discharge it to the same body of water from which it was obtained. This is known as a "once-through" system. One of the major considerations in siting power plants is the availability of an adequate source of high-quality once-through cooling water. If sufficient water for a once-through system is not available and other considerations prevail in determining the location of the plant, cooling water must be recirculated within the plant. In this case, some form of cooling device, an artificial pond with or without sprays, or a cooling tower, must be provided to keep the temperature from rising above the maximum level permissible or desirable for turbine operation. Because cooling devices obtain their cooling effect from evaporation, the dissolved solids concentration of closed cooling systems tends to increase, eventually reaching, if uncontrolled, a point where scaling of the condenser would interfere with heat transfer. A portion of the concentrated circulating water must therefore be discharged continually as blowdown to remove dissolved solids, and purer fresh water must be provided to make up for losses due to evaporation, blowdown, liquid carryover (drift), and leaks.

COMBUSTION PROCESS

In the basic combustion process, carbon and hydrogen in coal react with oxygen to form carbon dioxide and water. However, because of the complex nature of coal and the many other reactions occurring under actual combustion conditions in a boiler, a wide assortment of other emission species is produced. Some materials (e.g., sulfur oxides) are formed from other constituents in the coal; others (e.g., carbon monoxide) are products of incomplete combustion reactions. This section characterizes the bituminous coal consumed by this source type and describes the combustion process.

Coal Characterization

The American Society for Testing and Materials (ASTM) has classified coals into the 4 classes and 13 groups shown in Table 7 [4]. Each class and group is defined by a range of fixed carbon, volatile matter, and calorific value (heating value). For this program, bituminous coal is assumed to include all bituminous and subbituminous coal types.

Based on distribution of bituminous and lignite coal to electric utilities, 50% of bituminous coal for pulverized dry bottom utility boilers originates in the Appalachian region [20]. The Appalachian region consists of coal producing districts 1 to 8 and 13 as defined by the Bituminous Coal Act of 1937. Table 8 presents a characterization of Appalachian bituminous coal from the literature [21-24]. Although average concentrations are given for elemental composition, levels can vary significantly from state to state, mine to mine, and even within the thickness of a coal seam. The concentration of a particular element in coal can range over two orders of magnitude [21-24].

Pulverized Coal Combustion

Coal burns in a diffusion flame because the solid nature of the fuel prohibits mixing of the fuel and oxidant on a molecular scale. Processes involved in the combustion of a solid fuel are

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[20] Minerals Yearbook 1975, Volume I: Metals, Minerals, and Fuels. U.S. Department of the Interior, Bureau of Mines, Washington, D.C., 1977. 1550 pp.

[21] Swanson, V. E., J. H. Medlin, J. R. Hatch, S. L. Coleman, G. H. Wood, S. D. Woodruff, and R. T. Hildebrand. Collection, Chemical Analysis, and Evaluation of Coal Samples in 1975. Open-File Report 76-468, U.S. Department of the Interior, Denver, Colorado, 1976. 503 pp.

[22] Ruch, R. R., H. J. Gluskoter, and N. F. Shimp. Occurrence and Distribution of Potentially Volatile Trace Elements in Coal. EPA-650/2-74-054 (PB 238 091), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, July 1974. 96 pp.

[23] Kessler, T., A. G. Sharkey, Jr., and R. A. Friedel. Analysis of Trace Elements in Coal by Spark-Source Mass Spectrometry. Report of Investigations 7714, U.S. Department of the Interior, Pittsburgh, Pennsylvania, 1973. 8 pp.

[24] Magee, E. M., H. J. Hall, and G. M. Varga, Jr. Potential Pollutants in Fossil Fuels. EPA-R2-73-249 (PB 225 039), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, June 1973. 223 pp.

TABLE 7. CLASSIFICATION OF COALS BY RANK [4][a]

Reprinted from 1976 Annual Book of ASTM Standards, p. 213,
by permission of American Society for Testing and Materials.

Coal rank	Fixed carbon limits, % (dry, mineral-matter-free basis)		Volatile matter limits, % (dry, mineral-matter-free basis)		Calorific value limits, Btu per pound (moist,[b] mineral-matter-free basis)	
	Equal or greater than	Less than	Greater than	Equal or less than	Equal or greater than	Less than
Anthracitic:						
Meta-anthracite	98			2		
Anthracite	92	98	2	8		
Semianthricite[c]	86	92	8	14		
Bituminous:						
Low volatile bituminous coal	78	86	14	22		
Medium volatile bituminous coal	69	78	22	31		
High volatile A bituminous coal		69	31		14,000[d]	
High volatile B bituminous coal					13,000[d]	14,000
High volatile C bituminous coal					{11,500 10,500	13,000 11,500
Subbituminous:						
Subbituminous A coal					10,500	11,500
Subbituminous B coal					9,500	10,500
Subbituminous C coal					8,300	9,500
Lignite:						
Lignite A					6,300	8,300
Lignite B						6,300

[a] This classification does not include a few coals, principally nonbanded varieties, which have unusual physical and chemical properties and which come within the limits of fixed carbon or calorific value of the high-volatile bituminous and subbituminous ranks. All of these coals either contain less than 48 percent dry, mineral-matter-free fixed carbon or have more than 15,500 moist, mineral-matter-free British thermal units per pound.

[b] Moist refers to coal containing its natural inherent moisture but not including visible water on the surface of the coal.

[c] If agglomerating, classify in low-volatile group of the bituminous class.

[d] Coals having 69 percent or more fixed carbon on the dry, mineral-matter-free basis shall be classified according to fixed carbon, regardless of calorific value.

TABLE 8. ARITHMETIC MEAN OF PROXIMATE AND ULTIMATE ANALYSES AND ELEMENTAL COMPOSITION FOR APPALACHIAN COAL REGION SAMPLES

Constituent	Arithmetic mean	Number of samples	Reference
Moisture, %	2.8	158	21
Volatile matter, %	31.6	158	21
Fixed carbon, %	54.6	158	21
Ash, %	11.0	158	21
Hydrogen, %	4.9	158	21
Carbon, %	72.6	158	21
Nitrogen, %	1.3	158	21
Oxygen, %	7.8	158	21
Sulfur, %	2.3	158	21
Heating value, MJ/kg	30	158	21
Elements, ppm:			
Aluminum	1.8×10^{4}	350	21-23
Arsenic	2.6×10^{1}	350	21-23
Antimony	1.2	350	21-23
Barium	1.0×10^{2}	341	21,23
Beryllium	2.1	426	21-24
Bismuth	$<1.0 \times 10^{-1}$	10	22
Boron	2.9×10^{1}	413	21-24
Bromine	1.1×10^{1}	19	21,22
Cadmium	6.8×10^{-1}	350	21-23
Calcium	1.3×10^{3}	350	21-23
Cerium	1.4×10^{1}	10	22
Cesium	2.5×10^{1}	10	22
Chlorine	7.3×10^{2}	19	21,22
Chromium	2.0×10^{1}	426	21-24
Cobalt	6.8	426	21-24
Copper	2.2×10^{1}	426	21-24
Dysprosium	1.4	10	22
Erbium	2.6×10^{-1}	10	22
Europium	5.9×10^{-1}	10	22
Fluorine	7.8×10^{1}	350	21-23
Gadolinium	1.0	10	22
Gallium	6.5	426	21-24
Germanium	4.8	95	21,22,24
Gold	4.0×10^{-1}	10	22
Hafnium	1.2	10	22
Holmium	2.1×10^{-1}	10	22
Iodine	1.1	10	22
Iridium	$<2.0 \times 10^{-1}$	10	22
Iron	1.9×10^{4}	350	21-23
Lanthanium	9.3	350	21-23
Lead	1.5×10^{1}	350	21-23
Elements (continued):			
Lithium	2.7×10^{1}	341	21,23
Lutetium	1.2×10^{1}	10	22
Magnesium	6.9×10^{2}	350	21-23
Manganese	5.9×10^{2}	350	21-23
Mercury	1.4×10^{-1}	350	21-23
Molybdenum	3.1	426	21-24
Neodymium	1.2×10^{3}	10	22
Nickel	1.5×10^{1}	426	21-24
Niobium	5.4	341	21,23
Osmium	$<2.0 \times 10^{-1}$	10	22
Palladium	$<1.0 \times 10^{-1}$	10	22
Phosphorus	9.2×10^{-1}	19	21,22
Platinum	$<3.0 \times 10^{-1}$	10	22
Potassium	2.3×10^{3}	350	21-23
Praseodymium	2.1	10	22
Rhenium	$<2.0 \times 10^{-1}$	10	22
Rhodium	$<1.0 \times 10^{-1}$	10	22
Rubidium	3.7×10^{1}	10	22
Ruthenium	4.0×10^{-1}	10	22
Samarium	1.9	10	22
Scandium	5.1	341	21,23
Selenium	4.5	350	21-23
Silicon	2.7×10^{4}	350	21-23
Silver	2.5×10^{-2}	10	22
Sodium	3.3×10^{2}	350	21-23
Strontium	1.0×10^{2}	341	21,23
Tantalum	9.5×10^{-1}	10	22
Tellurium	3.4×10^{-1}	10	22
Terbium	3.2×10^{-1}	10	22
Thallium	1.0×10^{-1}	10	22
Thorium	4.8	341	21,23
Thulium	$<1.0 \times 10^{-1}$	10	22
Tin	2.4	95	21,22,24
Titanium	8.1×10^{2}	415	21-24
Tungsten	2.8×10^{-1}	10	22
Uranium	1.4	341	21,23
Vanadium	2.0×10^{1}	426	21-24
Ytterbium	9.8×10^{-1}	341	21,23
Yttrium	1.1×10^{1}	426	21-24
Zinc	1.8×10^{1}	426	21-24
Zirconium	5.0×10^{1}	350	21-23

shown in Figure 6 [9]. With the addition of radiant energy from an ignition device or the combustion zone, volatile components are vaporized and flow away from the solid surface, and the solid portion of the fuel begins to pyrolyze. At this point, no oxidation of the fuel at the surface occurs due to lack of intimate contact with the oxidant. A diffusion flame is established where the mixing of combustibles and oxidant forms a combustible mixture. This is noted as the primary combustion zone in Figure 6. Additional transfer of heat results in additional vaporization of volatiles, pyrolysis, and a rise in surface temperature of the solid to the incandescent range.

Radiant energy from incandescence promotes additional pyrolysis of the vapors. After the depletion of volatiles, oxidation of the solid commences. Oxygen diffuses to the solid surface and oxidation of the nonvolatiles occurs, resulting in the release of more heat. Carbon monoxide, carbon dioxide, water, hydrogen, nitrogen oxides, sulfur oxides, particles from noncombusted vapors, and impurities may form or begin to form in the combustion zone.

Directly downstream of the combustion zone is the postflame region. This region may be luminous, and therefore it is often considered as part of the flame itself. Many chemical and physical processes may occur in the postflame region because the reactants may be both gaseous and solid. Radical recombination (chain termination) reactions such as the recombination of atomic oxygen and the formation of water from atomic hydrogen and the hydroxyl radical occur as the combustion gases cool. Reaction of fuel components and their combustion products with other hydrocarbons, dehydrogenation of hydrocarbons to species of greater unsaturation, and the cracking of hydrocarbons are among the pyrolytic postflame reactions.

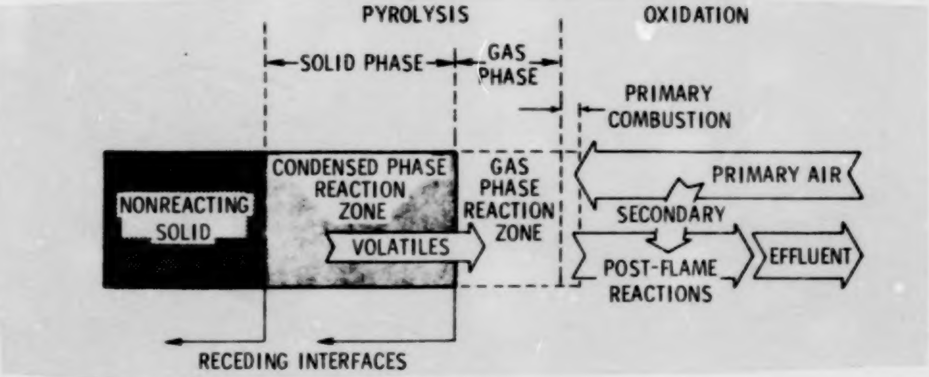
PYROLYSIS
OXIDATION
SOLID PHASE
GAS PHASE
PRIMARY COMBUSTION
CONDENSED PHASE REACTION ZONE
GAS PHASE REACTION ZONE
NONREACTING SOLID
VOLATILES
PRIMARY AIR
SECONDARY
POST-FLAME REACTIONS
EFFLUENT
RECEDING INTERFACES

Figure 6. Combustion of a solid [9].

Reprinted from the formation and emission of Trace Species by J.B. Edwards, p. 151, by permission of Ann Arbor Science Publishers, Inc.

SECTION 4

AIR EMISSIONS AND CONTROL TECHNOLOGY

SOURCE AND NATURE OF AIR EMISSIONS

Air emissions emanating from this source originate primarily from the combustion of pulverized bituminous coal in the boiler furnace. Other potential air emission sources are coal and ash handling and cooling towers when present.

Airborne emissions resulting from coal combustion include particulate matter, sulfur oxides, nitrogen oxides, carbon monoxide, hydrocarbons, polycyclic organic materials, and most elements. Mass emissions of particulate matter, sulfur oxides, and the elements found in combustion product gases as either particulate matter or vapors are directly related to the ash, sulfur, and individual elemental concentrations in the fuel. Nitrogen oxides arise from nitrogen compounds in coal and the nitrogen component of the combustion air. Carbon monoxide, hydrocarbons, and polycyclic organics are all products of incomplete combustion.

During combustion in a coal-fired furnace, the inorganic constituents (ash) of the coal are entrained in the effluent gas stream (fly ash) or removed as bottom ash. In a dry botton furnace, 60% to 90% (averaging 80% to 85%) of these noncombustible materials are entrained in the effluent gas stream [15, 25] and, unless collected in a control device, are emitted to the atmosphere. The remaining portion collects in the furnace and is periodically removed as bottom ash. The ash content of most bituminous coals ranges from 4% to 15% and averages about 11% [26].

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[25] Cuffe, S. T., and R. W. Gerstle. Emissions from Coal-fired Power Plants: A Comprehensive Summary. Public Health Service Publication 999-AP-35 (PB 174 708), U.S. Department of Health, Education, and Welfare, Cincinnati, Ohio, 1967. 26 pp.

[26] Smith, W. S., and C. W. Gruber. Atmospheric Emissions from Coal Combustion - An Inventory Guide. Public Health Service Publication 999-AP-24 (PB 170 851), U.S. Department of Health, Education, and Welfare, Cincinnati, Ohio, April 1966. 112 pp.

0272
0271

There are several mechanisms by which particulate matter, including aerosol mists, is formed during the combustion process and the subsequent flow of combustion products through the flue gas system. The inorganic species that are not volatile at combustion temperatures coalesce in the combustion zone to form a heterogeneous melt in which a small portion of the volatile inorganic and combustible materials is trapped. This material becomes the bottom ash and the bulk of the fly ash. As the combustion gases move away from the furnace and cool, the volatile inorganic combustion condense either onto the particles present in the gas stream or through self-nucleation. This process is essentially complete by the time the gases reach the electrostatic precipitator (ESP), the driving force being a 1,000°C plus temperature drop over 6 seconds or less which results in supersaturated conditions. Some additional material is added to the particles through adsorption of gaseous materials such as chlorine, bromine, fluorine, and mercury, and by gas phase reactions in the flue gas that produce additional condensable materials. Sulfuric acid mists are produced in the latter manner by the fly ash catalyzed conversion of sulfur dioxide to sulfur trioxide and the rise in flue gas dew point caused by the presence of sulfur [27].

Fly ash generally occurs as fine spherical particles. A typical coal ash particle size distribution has a bimodal distribution, with peaks in the regions of 0.07 μm and 0.6 μm for particle size diameter [28]. Chemical and physical descriptions of pulverized coal ash are found in Section 6.

Concentrations of trace elements emitted as either particles or vapors are closely related to the elemental composition of the coal. However, the concentrations found in fly ash are affected by the partitioning of elements between the fly ash and bottom ash. Concentrations of elements found in fly ash emitted after passing through particulate controls are further influenced by a mechanism known as particulate enrichment.

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[27] Hillenbrand, L. J., R. B. Engdahl, and R. E. Barrett. Chemical Composition of Particulate Air Pollutants from Fossil-Fuel Combustion Sources. EPA-R2-73-216 (PB 219 009), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, March 1973.

[28] Ragaini, R. C., and J. M. Ondov. Trace-Element Emissions from Western U.S. Coal-Fired Power Plants. Journal of Radioanalytical Chemistry, 37:679-691, 1977.

Three distinct classes of elements have been identified according to their partitioning behavior [29-33]. First are the elements that show no preference for bottom or fly ash. These elements are not volatilized in the combustion zone but form a melt of heterogeneous composition that becomes both bottom and fly ash. The second class consists of elements that partially volatilize in the combustion zone and condense onto fly ash particles in the flue gas as it cools. Elements belonging to this group are thus preferentially depleted from the botton ash and concentrated in the fly ash. The third class is made up of elements that are volatilized and essentially remain in the vapor state. These elements are thus emitted directly to the atmosphere as gases; their mass emission rate is directly proportional to their concentration in the coal and is independent of any particulate control device. It should also be noted that a number of elements do not fit well into any of the above classes but exhibit behavior intermediate between Classes I and II. The elements belonging to each class are listed in Table 9 [29-33].

Particulate enrichment is a result of the volatilization and subsequent condensation of the Class II elements mentioned above. Because smaller fly ash particles present a larger surface area per unit mass for condensation, they are the ones on which the

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[29] Davison, R. L., D. F. S. Natusch, J. R. Wallace, and C. A. Evans, Jr. Trace Elements in Fly Ash - Dependence of Con-concentration on Particle Size. Environmental Science and Technology, 8(13):1107-1113, 1974.

[30] Kaakinen, J. W., R. M. Jorden, M. H. Lawasani, and R. E. West. Trace Element Behavior in Coal-Fired Power Plant. Environmental Science and Technology, 9(9):862-869, 1975.

[31] Klein, D. H. A. W. Andren, J. A. Carter, J. F. Emery, C. Feldman, W. Fulkerson, W. S. Lyon, J. C. Ogle, Y. Talmi, R. I. VanHook, and N. Bolton. Pathways of Thirty-Seven Trace Elements Through Coal-Fired Power Plant. Environmental Science and Technology, 9(10):973-979, 1975.

[32] Ondov, J. M., R. C. Ragaini, and A. H. Biermann. Emissions and Particle-Size Distribution of Minor and Trace Elements at Two Western Coal-Fired Power Plants Equipped with Coal-Side Electrostatic Precipitators. Environmental Science and Technology, 13(8):946-953, 1979.

[33] Gladney, E. S. J. S. Small, G. E. Gordon, and W. H. Zoller. Composition and Size Distribution of In-Stack Particulate Material at a Coal-Fired Power Plant. Atmospheric Environment, 10(12):1071-1077, 1976.

A-3

TABLE 9. CLASSIFICATION OF ELEMENTS ACCORDING TO THEIR PARTITIONING BEHAVIOR [29-33]

Partitioning class	Elements
Class I - Elements equally distributed between bottom and fly ash	Aluminum, barium, beryllium, bismuth, calcium, cerium, cobalt, europium, hafnium, iron, lanthanum, lutetium, magnesium, manganese, neodymium, niobium, potassium, rubidium, samarium, scandium, silicon, sodium, strontium, tantalum, terbium, thorium, tin, titanium, ytterbium, yttrium, zirconium
Class II - Elements concentrating in fly ash	Antimony, arsenic, cadmium, copper, gallium, indium, lead, molybdenum, polonium, selenium, thallium, tungsten, zinc
Class III - Elements remaining in gas phase	Bromine, chlorine, fluorine, mercury
Elements intermediate between Classes I and II	Cesium, chromium, nickel, uranium, vanadium

Class II elements are concentrated on a per unit mass basis. This is of particular interest because the smaller particles are harder to remove from the flue gas and therefore make up a high percentage of the ash emitted after controls.

Sulfur oxides (SO_x) emissions result from the oxidation of the pyritic and organic sulfur found in coal. Since no more than a small percentage of the sulfur is converted to particulate sulfates [3, 34], the SO_x emission rate is almost totally dependent on the fuel sulfur content and the fuel feed rate to the boiler. Thus, SO_x emissions can be closely approximated by the following equation [35]:

$$SO_x = 2(R)(S) \tag{1}$$

where SO_x = emission rate of sulfur oxides, kg/hr
2 = molecular weight ratio of SO_2 (the primary SO_x species) to S
R = fuel flow rate, kg/hr
S = fraction of sulfur in the coal

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[34] Orning, A. A., C. H. Schwartz, and J. F. Smith. Minor Products of Combustion in Large Coal-Fired Steam Generators. ASME Peper No. 64-WA/FU-2, presented at the 1964 Winter Annual Meeting of the American Society of Mechanical Engineers, New York, New York, November 29 - December 4, 1964. 12 pp.

[35] McKnight, J. S. Effects of Transient Operating Conditions on Steam-Electric Generator Emissions. EPA-600/2-75-022 (PB 274 701), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, August 1975. 114 pp.

In the combustion zone, the fuel sulfur is rapidly converted to SO_2 and SO_3 although the concentration of the SO_3 formed initially is only about 0.5% of the SO_2 concentration. As the sulfur dioxide cools while traveling through the flue gas ducts, it is slowly oxidized to SO_3 by homogeneous gas phase reactions and by catalytic oxidation in the presence of iron oxide, vanadium pentoxide, and other metal oxides in the fly ash and ash deposits on the heat transfer surfaces [36-38]. Because these reactions are slow, equilibrium SO_2-SO_3 concentrations are not reached in the final exhaust gas. The initial SO_3 concentration is relatively independent of excess air at levels above 5% excess air. However, reducing excess air to a few tenths of 1% causes SO_3 concentrations to fall to nearly zero [39]. The SO_3 formed may react with moisture in the flue gas to produce sulfuric acid if stack temperatures drop below the acid dew point.

The nature of nitrogen oxide emissions is somewhat more complex than that of sulfur oxides because both the fuel and the combustion air are sources of nitrogen in the combustion zone. Combustion air is about 79% nitrogen, and coal contains from 0.5% to 2% nitrogen by weight in the form of pyroles, pyridines, quinolines, carbazoles, and amines [40]. Nitrogen oxide emissions usually represent less than 0.1% of the nitrogen entering the furnace[35], indicating that very little atmospheric nitrogen is converted to NO_x in the furnace. This is partially because the conversion of atmospheric nitrogen to nitrogen oxides (thermal NO_x formation) is highly temperature dependent and proceeds slowly at the relatively low flame temperatures (<1,530°C) encountered in a typical fuel-lean coal flame. On the other hand,

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[36] Corn, M., and R. T. Cheng. Interactions of Sulfur Dioxide with Insoluble Suspended Particulate Matter. Journal of the Air Pollution Control Association, 22(11):870-875, 1972.

[37] Vogel, R. F., B. R. Mitchell, and F. E. Massoth, Reactivity of SO_2 with Supported Metal Oxide-Alumina Sorbents. Environmental Science and Technology, 8(5):432-436, 1974.

[38] Wilson, J. S. and M. W. Redifer. Equilibrium Composition of Simulated Coal Combustion Products: Relationship to Fireside Corrosion and Ash Fouling. Journal of Engineering for Power, Transactions of the ASME, 96(A-2):145-152, 1974.

[39] Barrett, R. E., J. D. Hummel, and W. T. Reid. Formation of SO_3 in a Noncatalytic Combustor. Journal of Engineering for Power, Transactions of the ASME, 88(4):165-172, 1966.

[40] Vogt, R. A., and N. M. Laurendeau. Nitric Oxide Formation in Pulverized Coal Flames. PURDU-CL-76-08 (PB 263 277), National Science Foundation, Washington, D.C., September 1976. 92 pp.

fuel nitrogen conversion is readily accomplished at lower temperatures and contributes from 60% to 100% (averaging about 80%) of the nitrogen oxides formed at 730°C to 1,530°C. This is because the bond energies in coal are typically 80 kcal/mole to 100 kcal/mole compared to the 225 kcal/mole required for thermal nitrogen oxide formation [40]. The amount of fuel nitrogen oxidized depends on the excess air present; for low excess air levels (<5%) it is generally between 20% and 50% [41-44].

Nitrogen oxides are formed in the combustion zone, the primary constituent (approximately 95% of total NO_x) being nitric oxide (NO). The NO concentration attained depends on the flame temperature and the residence time in the furnace as NO decomposition reactions are rapidly quenched by the lower temperature at the furnace outlet. Further oxidation of NO continues with time but at a very slow pace compared to that for the time spent in the boiler system. Therefore, the concentrations of nitrogen oxides reached in the furnace remain relatively unchanged at the point of discharge. Other oxides of nitrogen include nitrogen dioxide (NO_2), which accounts for about 5% of the total NO_x, and trace amounts of nitrogen pentoxide (N_2O_5) and nitrous oxide (N_2O) [38, 45].

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[41] Song, Y. H., J. M. Beer, and A. F. Sarofim. Fate of Fuel Nitrogen during Pyrolysis and Oxidation. In: Proceedings of the Second Stationary Source Combustion Symposium, Volume IV. Fundamental Combustion Research. EPA-600/7-77-073d (PB 274 029), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, July 1977. pp. 79-100.

[42] Axworthy, A. E., G. R. Schneider, M. D. Shuman, and V. H. Dayan. Chemistry of Fuel Nitrogen Conversion to Nitrogen Oxides in Combustion. EPA-600/2-76-039 (PB 250 373), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, February 1976. 365 pp.

[43] Sternling, C. V., and J. O. L. Wendt. Kinetic Mechanisms Governing the Fate of Chemically Bound Sulfur and Nitrogen in Combustion. EPA-650/2-74-017 (PB 230 895), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, August 1972. 144 pp.

[44] Pershing, D. W. G. B. Martin, and E. E. Berkau. Influence of Design Variables on the Production of Thermal and Fuel NO from Residual Oil and Coal Combustion. In: Air - II. Control of NO_x and SO_x Emissions, AIChE Symposium Series, 71(148):1:19-29, 1975.

[45] Environmental Control Technology. TID-26758-P7, U.S. Atomic Energy Commission, Washington, D.C., November 11, 1974. 77 pp.

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Incomplete combustion is responsible for the formation of carbon monoxide and hydrocarbons, including polycyclic organic materials (POM). Thus, the coal combustion efficiency is the controlling factor in the production and emissions of these pollutants. Conditions necessary for the conversion of hydrocarbon fuels to carbon dioxide and water are sufficient time for the completion of the chemical reactions, sufficient temperature to heat the fuel through its decomposition stages and to ignite it, and sufficient turbulence to thoroughly mix the fuel and oxygen. In a furnace firing pulverized coal, the major limiting factor is the ability of the burner to provide sufficient turbulence in the very short time allowed for combustion.

Carbon monoxide (CO) formation is directly related to the fuel-air ratio. Fuel rich conditions stimulate CO formation with maximum CO concentrations occurring at minimum oxygen concentrations. CO emissions are generally low for dry bottom boilers.

Like CO, hydrocarbon emissions are dependent on the fuel-air ratio, and they appear in small concentrations even though excess oxygen is available in the furnace. Either incomplete mixing or variations of reactant concentrations in time permit isolated oxygen-deficient volumes of gas to escape combustion.

Polycyclic organic materials result from the combination of free radical species formed in the flame. The synthesis of these molecules is dependent on many combustion variables, including the presence of a chemically reducing atmosphere. Under this condition, radical chain propagation is enhanced, allowing the buildup of a complex POM molecule. A list of POM species encountered during sampling is presented later. Because POM compounds melt/sublime at about 200°C, which is approximately 50°C higher than most stack temperatures [6], they should be in the condensed phase when emitted.

Emissions from utility boilers caused by coal and ash handling and by evaporation and aerosol formation in cooling towers do not approach the magnitude of combustion-related emissions. In fact, the sum of the mass emissions from these sources totals less than 1% of the combustion mass emissions.

Emissions resulting from the handling of coal include particulate emissions of coal dust from wind entrainment, and gaseous emissions of carbon monoxide, methane, and other highly volatile hydrocarbons. These emissions arise primarily from coal storage piles. Ash handling emissions result from wind entrainment of exposed ash particles during ash conveying, transport, and disposal. Emissions from coal storage piles have been previously assessed [5], and emissions from ash handling are discussed in Section 6.

4-7

aa08
aa07

Cooling tower emissions are divided into two categories, fog and drift, with 20 μm particle size as the dividing point. Fog (<20 μm) results from condensation and consists of relatively pure water. Drift droplets have the composition of the cooling liquor, which has a total dissolved solids content on the order of 1,000 ppm, consisting mainly of calcium sulfate ($CaSO_4$)[46]. Drift deposition is controlled by many atmospheric variables, but typically, approximately 70% of drift droplets deposit within about 122 m [2].

EMISSIONS DATA

Data characterizing air emissions from dry bottom utility boilers burning pulverized bituminous coal have been reported extensively in the literature. In some cases, data are not reported with all of the descriptors necessary to define power plants in this specific category. For example, a boiler may be identified only as a coal-fired utility boiler, or as a dry bottom, coal-fired utility boiler. In assembling data for this report, it was assumed that all undefined coal types were bituminous. Since 97% of all coal fired by utilities is bituminous [2], this assumption is reasonable. In general, however, only units that could be identified as dry bottom pulverized were included in the data base. Emissions data were compiled from literature data, calculated from material balance considerations, and gathered in a sampling program on a typical boiler in this source category. The sampling program is described in detail in Appendix A.

Average emission factors determined for this source type are presented in Table 10. A detailed discussion of the data base for each emission species is given in the following subsections. Due to the variability in elemental concentrations of different bituminous coals, elemental emissions can vary by several orders of magnitude from the reported average values.

Particulate Emissions

Studies on dry bottom boilers have established that an average of 80% to 85% of the inorganic ash in coal is entrained in the effluent gas stream as fly ash. The suggested EPA emission factor for this source type, for uncontrolled particulate emissions, is thus 8.5A g of particulate matter/kg of coal burned, where A is the coal ash content in percent [25, 26, 47]. However, most

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[46] Carson, J. E. Atmospheric Impacts of Evaporative Cooling Systems. ANL/ES-53, Argonne National Laboratory, Argonne, Illinois, October 1976. 48 pp.

[47] Compilation of Air Pollutant Emission Factors, Second Edition. AP-42 (PB 264 194), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, February 1976.

TABLE 10. AVERAGE EMISSION FACTORS FOR DRY BOTTOM UTILITY BOILERS FIRING PULVERIZED BITUMINOUS COAL

	Literature data		MRC field sampling data	
Emission species	Uncontrolled emission factor, g/kg	Controlled emission factor, g/kg	Uncontrolled emission factor,[a] g/kg	Controlled emission factor,[a] g/kg
Elements:[f]				
Rhenium	<2.0 x 10^{-4}	-[i]		
Rhodium	<1.0 x 10^{-4}	-[i]		
Rubidium	3.7 x 10^{-2}	3.7 x 10^{-4}[g]		
Ruthenium	<1.0 x 10^{-4}	-[i]		
Samarium	1.9 x 10^{-3}	1.9 x 10^{-5}[g]		
Scandium	5.1 x 10^{-3}	5.1 x 10^{-5}[g]		
Selenium	4.5 x 10^{-3}	4.5 x 10^{-3}[h]	8.9 x 10^{-4}	1.3 x 10^{-4}
Silicon	2.7 x 10^{1}	2.7 x 10^{-1}[g]	8.7 x 10^{-3}	1.7 x 10^{-2}
Silver	2.5 x 10^{-5}	-[i]	<2.1 x 10^{-2}	0
Sodium	3.3 x 10^{-1}	3.3 x 10^{-3}[g]	2.1 x 10^{-1}	1.2 x 10^{-2}
Strontium	1.0 x 10^{-1}	1.0 x 10^{-3}[g]	3.8 x 10^{-2}	1.9 x 10^{-5}
Tantalum	9.5 x 10^{-4}	9.5 x 10^{-6}[g]		
Tellurium	3.4 x 10^{-4}	-[i]		
Terbium	3.2 x 10^{-4}	3.2 x 10^{-6}[g]		
Thallium	1.0 x 10^{-4}	1.0 x 10^{-4}[h]		
Thorium	4.8 x 10^{-3}	4.8 x 10^{-5}[g]		
Thulium	<1.0 x 10^{-4}	-[i]		
Tin	2.4 x 10^{-3}	2.4 x 10^{-5}[g]	<3.1 x 10^{-2}	1.8 x 10^{-4}
Titanium	8.1 x 10^{-1}	8.1 x 10^{-3}[g]	3.9 x 10^{-1}	1.1 x 10^{-4}
Tungsten	2.8 x 10^{-4}	2.8 x 10^{-4}[g]		
Uranium	1.4 x 10^{-3}	1.4 x 10^{-4}[j]		
Vanadium	2.0 x 10^{-2}	2.0 x 10^{-3}[j]	8.7 x 10^{-2}	1.2 x 10^{-4}
Ytterbium	9.8 x 10^{-4}	9.8 x 10^{-6}[g]		
Yttrium	1.1 x 10^{-2}	1.1 x 10^{-4}[g]		
Zinc	1.8 x 10^{-2}	1.8 x 10^{-2}[h]	<3.5 x 10^{-2}	6.4 x 10^{-4}
Zirconium	5.0 x 10^{-2}	5.0 x 10^{-4}[g]		

[a] Blanks indicate no emission measurement made.

[b] Ash content of coal as percent by weight.

[c] Sulfur content of coal as percent by weight.

[d] Not applicable.

[e] POM compounds which are known to be carcinogenic or as in a class of POM's that contain known carcinogens.

[f] Uncontrolled emission factors for elemental emissions are based on average elemental concentrations in coal (See Table 8) assuming 100% of each element is emitted.

[g] These elements are equally distributed between the bottom ash and fly ash according to Table 9 and therefore occur in the larger fly ash particles. On this basis, it is assumed that the controlled emissions of these elements are 1% of the concentration found in coal.

[h] Elements having partitioning behavior in Classes II or III according to Table 9. Controlled emissions are assumed to be equal to uncontrolled emissions.

[i] No information available.

[j] Elements with partioning behavior intermediate between Class I and Class II. Controlled emissions are assumed to be 10% of uncontrolled emissions.

(continued)

TABLE 10 (continued)

	Literature data		MRC field sampling data	
Emission species	Uncontrolled emission factor, g/kg	Controlled emission factor, g/kg	Uncontrolled emission factor,[a] g/kg	Controlled emission factor,[a] g/kg
Elements:[f]				
Rhenium	$<2.0 \times 10^{-4}$	-[i]		
Rhodium	$<1.0 \times 10^{-4}$	-[i]		
Rubidium	3.7×10^{-2}	3.7×10^{-4}[g]		
Ruthenium	$<1.0 \times 10^{-4}$	-[i]		
Samarium	1.9×10^{-3}	1.9×10^{-5}[g]		
Scandium	5.1×10^{-3}	5.1×10^{-5}[g]		
Selenium	4.5×10^{-3}	4.5×10^{-3}[h]	8.9×10^{-4}	1.3×10^{-4}
Silicon	2.7×10^{1}	2.7×10^{-1}[g]	8.7×10^{-3}	1.7×10^{-2}
Silver	2.5×10^{-5}	-[i]	$<2.1 \times 10^{-2}$	0
Sodium	3.3×10^{-1}	3.3×10^{-3}[g]	2.1×10^{-1}	1.2×10^{-2}
Strontium	1.0×10^{-1}	1.0×10^{-3}[g]	3.8×10^{-2}	1.9×10^{-5}
Tantalum	9.5×10^{-4}	9.5×10^{-6}[g]		
Tellurium	3.4×10^{-4}	-[i]		
Terbium	3.2×10^{-4}	3.2×10^{-6}[g]		
Thallium	1.0×10^{-4}	1.0×10^{-4}[h]		
Thorium	4.8×10^{-3}	4.8×10^{-5}[g]		
Thulium	$<1.0 \times 10^{-4}$	-[i]		
Tin	2.4×10^{-3}	2.4×10^{-5}[g]	$<3.1 \times 10^{-2}$	1.8×10^{-4}
Titanium	8.1×10^{-1}	8.1×10^{-3}[g]	3.9×10^{-1}	1.1×10^{-4}
Tungsten	2.8×10^{-4}	2.8×10^{-4}[g]		
Uranium	1.4×10^{-3}	1.4×10^{-4}[j]		
Vanadium	2.0×10^{-2}	2.0×10^{-3}[j]	8.7×10^{-2}	1.2×10^{-4}
Ytterbium	9.8×10^{-4}	9.8×10^{-6}[g]		
Yttrium	1.1×10^{-2}	1.1×10^{-4}[g]		
Zinc	1.8×10^{-2}	1.8×10^{-2}[h]	$<3.5 \times 10^{-2}$	6.4×10^{-4}
Zirconium	5.0×10^{-2}	5.0×10^{-4}[g]		

[a] Blanks indicate no emission measurement made.

[b] Ash content of coal as percent by weight.

[c] Sulfur content of coal as percent by weight.

[d] Not applicable.

[e] POM compounds which are known to be carcinogenic or as in a class of POM's that contain known carcinogens.

[f] Uncontrolled emission factors for elemental emissions are based on average elemental concentrations in coal (See Table 8) assuming 100% of each element is emitted.

[g] These elements are equally distributed between the bottom ash and fly ash according to Table 9 and therefore occur in the larger fly ash particles. On this basis, it is assumed that the controlled emissions of these elements are 1% of the concentrations found in coal.

[h] Elements having partioning behavior in Classes II or III according to Table 9. Controlled emissions are assumed to be equal to uncontrolled emissions.

[i] No information available.

[j] Elements with partioning behavior intermediate between Class I and Class II. Controlled emissions are assumed to be 10% of uncontrolled emissions.

of the boilers in this source category reportedly employ some form of particulate control [6]. Even those not reporting controls are believed to use some form of mechanical collector to reduce stack emissions.

Controlled emission factors vary greatly, depending on the control device being used. Control efficiencies for electrostatic precipitators (ESP's) and baghouses can exceed 99%. An average controlled emission factor, based on source test data reported in NEDS [6], is 0.21 A, corresponding to a 97.5% control efficiency. A listing of the source test data is given in Appendix B. Other values can be used for controlled emission factors, as appropriate, for more detailed or site specific assessments.

The New Source Performance Standard for this source was recently revised. The old particulate standard of 43 g/GJ (0.1 lb/10^6 Btu) was lowered to 13 g/GJ (0.03 lb/10^6 Btu) [48, 49, 50]. In terms of the average coal for this source type (heating value 27.2 MJ/kg and ash content of 12.6%), the new standard corresponds to a controlled emission factor of 0.35 g/kg and a control efficiency of 99.7%.

Field sampling data collected by MRC at a utility boiler controlled by two electrostatic precipitators in series is presented in Table 11. Samples were collected with the Source Assessment Sampling System (SASS) train and with a modified EPA Method 8 train equipped with a filter. (Details of the sampling and analysis procedures are given in Appendix A.) The ESP's effected a 97% reduction in particulate emissions. Although the SASS train data to not fall in the range of the modified EPA Method 8 data, the data points are too few to draw any statistical conclusions. Particle size distributions measured for uncontrolled and controlled emissions are listed in Table 12, which illustrates that the collection efficiency of the ESP increases as the particle size increases.

Nitrogen Oxides Emissions

Emissions of nitrogen oxides were not measured during the MRC sampling effort because of the extensive work done in this area, and because such data do not provide an insight into any of the

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[48] Chaput, L. S. Federal Standards of Performance for New Stationary Sources of Air Pollution: A Summary of Regulations. Journal of the Air Pollution Control Association, 26(11):1055-1060, 1976.

[49] Costle, D. M. New Source Performance Standards for Coal-Fired Power Plants. Journal of the Air Pollution Control Association, 29(7):690-692, 1979.

[50] Tabler, S. K. Federal Standards of Performance for New Stationary Sources of Air Pollution: A Summary of Regulations. Journal of the Air Pollution Control Association, 29(8):803-811, 1979.

TABLE 11. PARTICULATE EMISSION FACTORS OBTAINED IN MRC TEST PROGRAM, g/kg

Sampling method	Uncontrolled	Controlled
Modified EPA Method 8		
Run 1	26	1.3
Run 2	15	0.27
Run 3	31	0.47
SASS train	47	0.069

TABLE 12. SASS[a] PARTICULATE SIZE DATA REPORTED AS A PERCENT OF THE TOTAL PARTICULATE MASS EMISSIONS, AS OBTAINED IN MRC TEST PROGRAM

Particle size, μm	Weight percent of uncontrolled emissions[b]	Weight percent of controlled emissions
<1 (filter)	0.83	65
1 to 3 (small cyclone)	20.4	0.1
3 to 10 (middle cyclone)	43.4	3
<10 (larger cyclone)	35	0.8
Probe wash	0.44	31.1

[a] Source assessment sampling system.

[b] Does not add to 100 percent because of round off error.

Sulfur Oxides and Particulate Sulfate Emissions

Sulfur oxides emissions data reported in the literature and in NEDS (see Appendix B) give an average uncontrolled emission factor of 19S g/kg, where S is the percent sulfur in the coal [6,26,47]. This is close to the theoretical maximum (for SO_2) of 20S g/kg and indicates that nearly all the fuel sulfur is released as SO_x. Sulfur emissions are primarily in the form of SO_2, with only a small amount (1%-3%) of SO_3 [55,56].

Emissions data obtained during MRC's field sampling program is summarized in Table 13. Details are given in Appendix A. Results agree well with previously published data and show that the percentage of sulfur emitted as SO_3 and particulate sulfate is relatively low (≤2.0%).

Revised New Source Performance Standards for SO_2 call for a ceiling level on emissions of 520 g/GJ (1.2 lb/10^6 Btu) and at least a 90% reduction in emissions for plants with a controlled emission level of greater than 260 g/GJ (0.6 lb/10^6 Btu). Plants with controlled emissions of less than 260 g/GJ must achieve at least a 70% reduction in emissions [49,50]. For the average coal of this source type, a 70% reduction would be needed, corresponding to a controlled emission factor of 5.7 S g/kg.

Carbon Monoxide Emissions

Carbon monoxide emissions from dry bottom utility boilers were not measured during the MRC sampling program because emission levels are very low. Literature values range between 0.2 g/kg and 0.5 g/kg (not counting cases below the detection limit); while NEDS data give a higher average value of 0.76 g/kg (see Appendix B) [6,25,26,47]. The overall average used in this report is 0.5 g/kg.

Hydrocarbon Emissions

Relatively few measurements have been made of hydrocarbon emissions from coal-fired utility boiler. Emission levels are low because of the good combustion conditions that exist for this source type. Emission factors reported in the literature range from 0.08 g/kg to 0.15 g/kg; limited NEDS data (see Appendix B)

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[55] Cuffe, S. T., R. W. Gerstle, A. A. Orning, and C. H. Schwartz. Air Pollutant Emissions from Coal-Fired Power Plants, Report No. 1. Journal of the Air Pollution Control Association, 14(9):353-362, 1964.

[56] Gerstle, R. W., S. T. Cuffe, A. A. Orning, and C. H. Schwartz. Air Pollutant Emissions from Coal-Fired Power Plants, Report No. 2. Journal of the Air Pollution Control Association, 14(9):59-64, 1965.

TABLE 13. EMISSIONS OF SO_2, SO_3, AND PARTICULATE SULFATE OBTAINED IN MRC TEST PROGRAM

Sampling location and test number	Coal sulfur content, %	Emission factors, g/kg of coal feed			AP-42 SO_x emission factor, g/kg	Percent agreement of measured values with AP-42	Fraction of SO_x as SO_3, %
		Particulate sulfate as SO_4	Sulfur trioxide and sulfuric acid mist as SO_3	sulfur dioxide as SO_2			
Mechanical collector outlet							
Run No. 1							
Field analysis	2.23	_[a]	0.30	49.8	42.4	119	0.6
Lab analysis		<0.057	0.48	23.0	42.4	55	2.0
Continuous analyzer		_[a]	_[a]	44.5	42.4	106	_[a]
Run No. 2							
Field Analysis	2.45	_[a]	0.17	52.4	46.6	112	0.33
Lab analysis		<0.059	0.31	48.0	46.6	104	0.64
ESP outlet							
Run No. 1							
Lab analysis	1.81	0.0006	0.26	31.8	34.4	94	0.81
Continuous analyzer		_[a]	_[a]	39.2	34.4	113	_[a]
Run No. 2							
Lab analysis	1.99	<0.0002	0.26	34.7	37.8	93	0.74
Continuous analyzer		_[a]	_[a]	40.2	37.8	106	_[a]
Run No. 3							
Lab analysis	1.72	0.001	0.22	33.1	32.7	102	0.66
Continuous analyzer		_[a]	_[a]	43.1	32.7	131	_[a]

[a] No data available.

average 0.30 g/kg [6,25,26,47]. Measurements made by MRC for low molecular weight hydrocarbons (C_6 and under as measured by GC-FID) yielded even lower values, averaging 0.02 g/kg. An overall average value of 0.1 g/kg is adopted for assessment purposes in this report.

POM and PCB Emissions

Polycyclic organic materials (POM's) constitute an important class of organic emissions because a number of them are known or suspected carcinogens [57]. Polychlorinated biphenyl compounds (PCB's) are also known to be hazardous although they have not been detected in emissions from coal-fired power plants. POM emissions data has been reported for this source type [55, 56, 58]; however, most of the measurements were made with older sampling and analytical techniques that have been superseded. Consequently, in this program, tests were made for POM's and PCB's using the SASS train for sample collection followed by GC/MS analysis.

Previously reported data for POM's show a range in emission factors for total POM's of 8 μg/kg to 44 μg/kg, with an average of 15 μg/kg. No significant difference was observed before and after particulate control devices. For carcinogenic POM's, the range in emission factors was 0.5 μg/kg to 16 μg/kg with an average of 4 μg/kg [55, 56, 58]. One test where the boiler was operated at partial load gave a total POM emission factor of 88 μg/kg before control and 16 μg/kg after control [55].

POM data gathered in MRC's sampling program is presented in Table 14. Results correspond closely with previous data and indicate that older measurement methods were effective in the capture and detection of POM's. Averaging the MRC data with the older data gives an average emission factor for total POM's of 16 μg/kg and a carcinogenic POM value of 4 μg/kg.

No PCB emissions were found. Table 15 lists the analytical detection limits for the method used in the PCB analysis.

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[57] Biologic Effects of Atmospheric Pollutants - Particulate Polycyclic Organic Matter. National Academy of Sciences, Washington, D.C., 1972. 361 pp.

[58] Hangebrauck, R. P., D. J. von Lehmden, and J. E. Meeker. Emissions of Polynuclear Hydrocarbons and Other Pollutants from Heat-Generation and Incineration Processes. Journal of the Air Pollution Control Association, 14(7):267-278, 1964.

TABLE 14. POM EMISSION FACTORS OBTAINED
DURING MRC TEST PROGRAM
(μg/kg)

POM species	Uncontrolled (at mechanical collector outlet)	Controlled (at ESP outlet)
Dibenzothiophene	<0.06	0.07
Anthracene/phenanthrene	0.12	1.8
Methylanthracenes/phenanthrenes	1.9	9.0
Dimethylanthracenes/phenanthrenes	8.2	10.8
Fluoranthene	0.60	0.52
Pyrene	1.1	1.0
Methylfluoranthenes/pyrenes	2.9	1.6
Benz(c)phenanthrene[a]	0.18	0.15
Chrysene/benz(a)anthracene[a]	0.60	0.37
Dimethylbenz(a)anthracenes[a]	1.7	1.8
Benzofluoranthrenes[a]	<0.06	<0.07
Benzopyrenes (and perylene)[a]	0.30	0.22
Methylchloranthrenes[a]	<0.3	<0.4
Indeno(1,2,3-c,d)pyrene[a]	<0.06	<0.07
Dibenz(a,h)anthracene[a,b]	<0.06	<0.07
Dibenz(c,g)carbazole[a]	<0.3	<0.4
Dibenzopyrenes[a]	1.8	<0.37
Methylchrysenes[a,b]	1.6	1.6
Anthanthrene/benzo(ghi)perylene	<0.03	<0.07
Total	21	29

[a] Known or suspected carcinogens.

[b] May include isomers.

TABLE 15. DETECTION LIMITS FOR PCB COMPOUNDS EXPRESSED AS MINIMUM DETECTABLE EMISSION FACTORS (MRC DATA)

PCB	Detection limit, μg/kg
Chlorobiphenyls	0.26
Dichlorobiphenyls	0.04
Trichlorobiphenyls	0.14
Tetrachlorobiphenyls	0.14
Pentachlorobiphenyls	0.04
Hexachlorobiphenyls	0.63
Heptachlorobiphenyls	0.07
Octachlorobiphenyls	0.07
Nonachlorobiphenyls	0.11
Decachlorobiphenyls	0.07

Elemental Emissions

As mentioned earlier in this chapter, several studies have characterized elemental emissions from coal-fired power plants [29-33]. These studies have categorized elements according to their partitioning behavior (see Table 9), whereby the more volatile elements are preferentially emitted with the fly ash or in the vapor phase. Less volatile elements are distributed equally between ash and fly ash. The elemental emission factors given in Table 10 were calculated from the average coal composition (Table 8) and the observed partitioning behavior. Uncontrolled emission factors were based on the average elemental concentrations in coal assuming that 100% of each element is emitted. Controlled emission factors for elements in Class II or III according to Table 9 were assumed to be equal to the uncontrolled emission factors, a worst case estimate based on their volatility and tendency to condense on smaller particles which are not collected as efficiently by ESP's. Elements with partitioning behavior intermediate between Classes I and II were assumed to have controlled emissions that are 10% of uncontrolled emissions because they show some tendency to condense on smaller particles. Elements in Class I were assumed to have controlled emissions that are 1% of uncontrolled emissions corresponding to a 99% control efficiency. Class I elements behave the same as total particulate matter, and high efficiency ESP's can achieve particulate control efficiencies of 99+%.

Elemental emissions data obtained during MRC's sampling program is given in Table 16. Values are in reasonable agreement with Table 10. The uncontrolled emission factor for silicon is

TABLE 16. ELEMENTAL EMISSION FACTORS OBTAINED DURING MRC TEST PROGRAM[a]
(g/kg)

Element	Uncontrolled (at mechanical collector outlet)	Controlled (at ESP outlet)
Aluminum	<5.5	2.5×10^{-3}
Antimony	2.5×10^{-2}	1.0×10^{-3}
Arsenic	4.2×10^{-2}	2.3×10^{-4}
Barium	$<7.5 \times 10^{-2}$	1.2×10^{-5}
Boron	2.7×10^{-2}	1.8×10^{-2}
Cadmium	1.9×10^{-2}	8.3×10^{-5}
Calcium	<0.59	2.0×10^{-3}
Chromium	5.1×10^{-2}	2.7×10^{-2}
Cobalt	9.2×10^{-3}	6.3×10^{-4}
Copper	0.13	6.4×10^{-4}
Iron	2.2	9.6×10^{-2}
Lead	2.8×10^{-2}	6.0×10^{-4}
Magnesium	3.2×10^{-1}	5.9×10^{-4}
Manganese	1.2×10^{-2}	2.7×10^{-3}
Mercury	7.1×10^{-5}	2.1×10^{-5}
Molybdenum	1.4×10^{-2}	2.0×10^{-3}
Nickel	2.9×10^{-2}	1.4×10^{-2}
Phosphorus	2.5×10^{-1}	1.2×10^{-3}
Selenium	8.9×10^{-4}	1.3×10^{-4}
Silicon	8.7×10^{-3}	1.7×10^{-2}
Silver	$<2.1 \times 10^{-2}$	0
Sodium	2.1×10^{-1}	1.2×10^{-2}
Strontium	3.8×10^{-2}	1.9×10^{-5}
Tin	$<3.1 \times 10^{-2}$	1.8×10^{-4}
Titanium	3.9×10^{-1}	1.1×10^{-4}
Vanadium	8.7×10^{-2}	1.2×10^{-4}
Zinc	$<3.5 \times 10^{-2}$	6.4×10^{-4}

[a] Samples were taken with the SASS train.

believed to be low because of the difficulty in dissolving silica in the analysis procedure. In every other case, controlled emission factors were lower than uncontrolled ones, even for the volatile elements (arsenic, mercury, and selenium). These results must be interpreted with caution because samples were obtained with the Source Assessment Sampling System (SASS) train, a method which does not traverse the stack or sample isokinetically. Thus the samples taken before the ESP may not be representative of the particulate loading across the entire stack. (See Appendix A for more details on the procedure.)

POTENTIAL ENVIRONMENTAL EFFECTS

Air emissions released during the combustion of pulverized bituminous coal in dry bottom utility boilers enter the atmosphere and are dispersed throughout the environment. These emissions have an adverse impact on the quality of air, water, and land resources, property, vegetation, and animal and human health. While the fate and environmental effects of many trace pollutants are not known, those of the major species are well documented [59-61].

The purpose of this section is to evaluate the potential environmental effects due to air emissions from an average plant in this source category and from all boilers in the category. This is done by defining an average source and the range of actual sources and then comparing the expected maximum ground level concentrations of emitted pollutants (based on the emission factors in Table 10) with air quality standards. In addition, the percent contributions of this source category to the state and national emission burdens of criteria pollutants are presented.

Average Plant and Range of Actual Plants

As discussed previously in Section 3, the average source is defined as a dry bottom utility boiler firing pulverized bituminous coal at a rate of 11 kg/s. The coal has an ash content of 12.6%, a sulfur content of 2.08%, and the elemental composition given

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[59] Air Pollution; Volume I: Air Pollution and Its Effects Second Edition, A. C. Stern, ed. Academic Press, New York, New York, 1968. 694 pp.

[60] Leighton, P. A. Photochemistry of Air Pollution. Academic Press, New York, New York, 1961. 300 pp.

[61] Seinfeld, J. H. Air Pollution - Physical and Chemical Foundamentals. McGraw-Hill Book Company, New York, New York, 1975. 523 pp.

in Table 8. The stack height of the boiler is 93 m. The firing rate is based on an average firing capacity value calculated from a National Emissions Data System (NEDS) listing for this source type, and the stack height and coal ash and sulfur content are also based on NEDS data [6].

Sources in the NEDS listing range from a firing rate of 2.2 g/s with a stack height of 53 m to a firing rate of 75.6 kg/s with a stack height of 244 m.

Ambient Source Severity

The potential environmental effects of air emissions from a point source can be measured in several ways. The method used here is to determine the maximum ground level concentration of each emission species downwind from the average plant and compare this value to the primary ambient air quality standard for criteria emissions [62-64] or to a reduced threshold limit value (TLV) [65] for the noncriteria emission species.

The comparison is called ambient source severity, S_a, and is defined as:

$$S_a = \frac{\overline{\chi}_{max}}{F} \tag{2}$$

where $\overline{\chi}_{max}$ = maximum time-averaged ground level concentration for each emission species, g/m^3

F = primary ambient air quality standard for criteria pollutants (particulate matter, sulfur oxides, nitrogen oxides, carbon monoxide, and hydrocarbons), g/m^3

or

F = TLV x 8/24 x 1/100, for noncriteria emission species, g/m^3

where TLV = threshold limit value for each species, g/m^3

8/24 = correction factor to adjust the TLV to a 24-hr exposure level (3)

1/100 = an arbitrary safety factor to allow for a higher risk general population

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[62] Federal Register, 36:22384, November 25, 1971.

[63] Federal Register, 43:46258, October 5, 1978.

[64] Federal Register, 44:8220, February 8, 1979.

[65] TLVs® Threshold Limit Values for Chemical Substances and Physical Agents in the Workroom Environment with Intended Changes for 1976. American Conference of Governmental Industrial Hygienists, Cincinnati, Ohio, 1976. 97 pp.

The value of $\overline{\chi}_{max}$ for an average source is calculated from

$$\overline{\chi}_{max} = \chi_{max} \left(\frac{t_o}{t} \right)^{0.17} \qquad (4)$$

where $\chi_{max} = \dfrac{2\,Q}{\pi e \bar{u} H^2}$ for evaluated point sources (5)

and

Q = emission rate, g/s
π = 3.14
$\underline{e}$ = 2.72
$\bar{u}$ = average wind speed, 4.5 m/s (national average)
t_o = short-term averaging time, 3 min
t = averaging time, min
H = height of emission release, m

The equation for χ_{max} (Equation 5) is derived from the general plume dispersion equation for an elevated point source for average U.S. atmospheric stability conditions [66].

The maximum ambient severity of pollutants may be calculated using the mass emission rate, Q, the height of the emissions, H, and the TLVs (used for noncriteria pollutants) according to the equations summarized in Table 17. These equations are developed in Appendix C.

TABLE 17. POLLUTANT SEVERITY EQUATIONS FOR ELEVATED SOURCES

Pollutant	Severity equation
Particulate matter	$S_p = \frac{70\,Q}{H^2}$
SO_x	$S_{SO_x} = \frac{50\,Q}{H^2}$
NO_x	$S_{NO_x} = \frac{315\,Q}{H^{2.1}}$
Hydrocarbons	$S_{HC} = \frac{162\,Q}{H^2}$
CO	$S_{CO} = \frac{0.78\,Q}{H^2}$
Others	$S_a = \frac{5.5\,Q}{TLV \cdot H^2}$

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[66] Turner, D. B. Workbook of Atmospheric Dispersion Estimates. Public Health Service Publication 999-AP-26 (PB 191 482), U.S. Department of Health, Education, and Welfare, Cincinnati, Ohio, 1969. 62 pp.

The ambient air quality standards used for criteria pollutants and the TLV's used for noncriteria pollutants are listed in Tables 18 and 19, respectively.

Emission rates (Q) are equal to emission factors times coal consumption rates. Emission factors used for the severity calculations were selected from Table 10 using literature data for uncontrolled and controlled emissions. An exception was the emission factor for total POM's, where MRC sampling was included to give a value of 16 μg/kg.

For source types with significant plume rise, the value of H in Equation 5 must be corrected to include the plume rise. An examination of NEDS data for this source shows that the increase in emission height for a typical plant is $\sim$60%.

Ambient severities were calculated for the average plant and for the largest plant reported in NEDS. The largest plant was found to fire coal at the rate of 75.6 kg/s, versus a rate of 11 kg/s for the average plant. This provides a range of severities for the whole source category. The ambient severities for the average and largest plants, and the values used to calculate them, are presented in Tables 20 and 21, respectively. Ambient severities for criteria pollutants only are given for the largest plant because the data are only 50% higher than those for the average plant. The increase in plant size is nearly offset by the increase in stack height. For the average plant with particulate emissions control, no emissions have ambient severities greater than 1.0. Three criteria pollutants and eleven elements have ambient severities >0.05.

TABLE 18. AMBIENT AIR QUALITY STANDARDS FOR CRITERIA POLLUTANTS [62-64]

Emission	Ambient air quality standard, mg/m^3
Particulate matter	0.260
NO_x	0.100
SO_x	0.365
CO	40.0
Hydrocarbons	0.160[a]

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[a] There is no primary ambient air quality standard for hydrocarbons. The value of 160 μ/m^3 used for hydrocarbons in this report is a recommended guideline for meeting the primary ambient air quality standard for oxidants.

TABLE 19. THRESHOLD LIMIT VALUES USED FOR NONCRITERIA POLLUTANTS [65]

Emission	TLV, mg/m³	Compound used for TLV
POM	0.2	POM
POM (carcinogenic)	0.001	Carcinogen[a]
PCB	0.5	Chlorodiphenyl (54% chlorine) skin
Sulfate	1.0	Sulfuric acid, H_2SO_4
Elements:		
Aluminum	10	Alundum, Al_2O_3
Arsenic	0.5	Arsenic and compounds
Antimony	0.5	Antimony and compounds
Barium	0.5	Barium (soluble compounds)
Beryllium	0.002	Beryllium
Bismuth	10	-[b]
Boron	10	Boron oxide
Bromine	0.7	Bromine
Cadmium	0.05	Cadmium oxide fume
Calcium	5	Calcium oxide
Cerium	10	-[b]
Cesium	2	Cesium hydroxide
Chlorine	7	Hydrogen chloride
Chromium	0.1	Chromic acid and chromates
Cobalt	0.1	Cobalt metal, dust and fume
Copper	1	Copper, dusts and mists
Dysprosium	10	-[b]
Erbium	10	-[b]
Europium	10	-[b]
Fluorine	2	Fluorine
Gadolinum	10	-[b]
Gallium	10	-[b]
Germanium	10	-[b]
Gold	10	-[b]
Hafnium	0.5	Hafnium
Holmium	10	-[b]
Iodine	1	Iodine
Iridium	10	-[b]
Iron	5	Iron oxide fume
Lanthanum	10	-[b]
Lead	0.15	Lead, inorganic fumes and dusts
Lithium	10	-[b]
Lutetium	10	-[b]
Magnesium	10	Magnesium oxide fume
Manganese	5	Manganese and compounds
Mercury	0.05	All forms except alkyl

(continued)

TABLE 19 (continued)

Emission	TLV, mg/m^3	Compound used for TLV
Molybdenum	5	Soluble compounds
Neodymium	10	-[b]
Nickel	0.1	Soluble compounds
Niobium	10	-[b]
Osmium	0.002	Osmium tetoxide
Palladium	10	-[b]
Phosphorus	1	Phosphoric acid
Platinum	0.002	Soluble salts
Potassium	2	Potassium hydroxide
Praeseodymium	10	-[b]
Rhenium	10	-[b]
Rhodium	0.1	Metal fumes and dusts
Rubidium	10	-[b]
Ruthenium	10	-[b]
Samarium	10	-[b]
Scandium	10	-[b]
Selenium	0.2	Selenium compounds
Silicon	10	Silicon
Silver	0.01	Metal and soluble compounds
Sodium	2	Sodium hydroxide
Strontium	10	-[b]
Tantalum	5	Tantalum
Tellurium	0.1	Tellurium
Terbium	10	-[b]
Thallium	0.1	Thallium soluble compounds
Thorium	10	-[b]
Thulium	10	-[b]
Tin	10	Tin oxide
Titanium	10	Titanium dioxide
Tungsten	1	Tungsten and compounds, soluble
Uranium	0.2	Soluble and insoluble compounds
Vanadium	0.5	Vanadium pentoxide dust, V_2O_5
Ytterbium	10	-[b]
Yttrium	1	Yttrium
Zinc	5	Zinc oxide fume
Zirconium	5	Zirconium compounds

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[a] Value for carcinogenic compounds corresponds approximately to the minimum detectable limit.

[b] For elements not having an appropriate TLV, the TLV for nuisance particulate, 10 mg/m^3, was used.

TABLE 20. EMISSION RATES AND AMBIENT SEVERITIES OF AN AVERAGE PLANT[a]

Pollutant	Emission rate, g/s		Ambient severity	
	Uncontrolled	Controlled	Uncontrolled	Controlled
Particulate[b]	1.2×10^{3}	2.9×10^{1}	3.6	9.0×10^{-2}
NO_x	1.1×10^{2}	8.8×10^{1}	9.7×10^{-1}	7.8×10^{-1}
SO_x[c]	4.3×10^{2}	1.3×10^{2}	9.3×10^{-1}	2.8×10^{-1}
CO	5.5	-[d]	1.9×10^{-4}	-[d]
Hydrocarbons	1.1	-[d]	7.8×10^{-3}	-[d]
POM (total)	1.8×10^{-4}	-[d]	2.2×10^{-4}	-[d]
POM (carcinogenic)	4.4×10^{-5}	-[d]	1.0×10^{-2}	-[d]
Elements:				
Aluminum	2.0×10^{2}	2.0	4.9	4.9×10^{-2}
Antimony	1.3×10^{-2}	1.3×10^{-2}	6.3×10^{-3}	6.3×10^{-3}
Arsenic	2.9×10^{-1}	2.9×10^{-1}	1.4×10^{-1}	1.4×10^{-1}
Barium	1.1	1.1×10^{-2}	5.2×10^{-1}	5.2×10^{-3}
Beryllium	2.3×10^{-2}	2.3×10^{-4}	2.8	2.8×10^{-2}
Bismuth	$<1.1 \times 10^{-3}$	$<1.1 \times 10^{-5}$	$<2.6 \times 10^{-5}$	$<2.6 \times 10^{-7}$
Boron	3.2×10^{-1}	3.2×10^{-1}[e]	7.5×10^{-3}	7.5×10^{-3}
Bromine	1.2×10^{-1}	1.2×10^{-1}	4.1×10^{-2}	4.1×10^{-2}
Cadmium	7.5×10^{-3}	7.5×10^{-3}	3.6×10^{-2}	3.[illegible] x 10^{-2}
Calcium	1.4×10^{1}	1.4×10^{-1}	6.7×10^{-1}	6.7×10^{-3}
Cerium	1.5×10^{-1}	1.5×10^{-3}	3.7×10^{-3}	3.7×10^{-5}
Cesium	2.8×10^{-1}	2.8×10^{-3}	3.3×10^{-2}	3.3×10^{-4}
Chlorine	8.0	8.0	2.8×10^{-1}	2.8×10^{-1}
Chromium	2.2×10^{-1}	2.2×10^{-2}	5.2×10^{-1}	5.2×10^{-2}
Cobalt	7.5×10^{-2}	7.5×10^{-4}	1.8×10^{-1}	1.8×10^{-3}
Copper	2.4×10^{-1}	2.4×10^{-1}	6.0×10^{-2}	6.0×10^{-2}
Dysprosium	1.5×10^{-2}	1.5×10^{-4}[f]	3.7×10^{-4}	3.7×10^{-6}
Erbium	2.9×10^{-3}	2.9×10^{-5}[f]	6.7×10^{-3}	6.7×10^{-7}
Europium	6.5×10^{-3}	6.5×10^{-5}	1.6×10^{-4}	1.6×10^{-6}
Fluorine	8.6×10^{-1}	8.6×10^{-1}	1.0×10^{-1}	1.0×10^{-1}
Gadolinium	1.1×10^{-2}	1.1×10^{-4}[f]	2.6×10^{-4}	2.6×10^{-6}
Gallium	7.2×10^{-2}	7.2×10^{-2}	1.7×10^{-3}	1.7×10^{-3}
Germanium	$<5.3 \times 10^{-2}$	$<5.3 \times 10^{-2}$[e]	$<1.3 \times 10^{-3}$	$<1.3 \times 10^{-3}$
Gold	$<1.1 \times 10^{-3}$	$<1.1 \times 10^{-5}$[f]	$<2.6 \times 10^{-5}$	$<2.6 \times 10^{-7}$
Hafnium	1.3×10^{-2}	1.3×10^{-4}	6.3×10^{-3}	6.3×10^{-5}
Holmium	2.3×10^{-2}	2.3×10^{-4}[f]	5.6×10^{-4}	5.6×10^{-6}
Iodine	1.2×10^{-2}	1.2×10^{-2}[e]	2.9×10^{-3}	2.9×10^{-3}
Iridium	$<2.2 \times 10^{-3}$	$<2.2 \times 10^{-5}$[f]	$<5.2 \times 10^{-3}$	$<5.2 \times 10^{-7}$
Iron	2.1×10^{2}	2.1	1.0×10^{1}	1.0×10^{-1}
Lanthanum	1.0×10^{-1}	1.0×10^{-3}	2.5×10^{-3}	2.5×10^{-5}
Lead	1.7×10^{-1}	1.7×10^{-1}	2.6×10^{-1}	2.6×10^{-1}
Lithium	2.8×10^{-1}	2.8×10^{-3}[f]	7.1×10^{-3}	7.1×10^{-5}
Lutetium	1.3×10^{-3}	1.3×10^{-5}	3.2×10^{-5}	3.2×10^{-7}
Magnesium	7.6	7.6×10^{-2}	1.8×10^{-1}	1.8×10^{-3}
Manganese	6.5	6.5×10^{-2}	3.1×10^{-1}	3.1×10^{-3}
Mercury	2.6×10^{-3}	2.6×10^{-3}	1.3×10^{-2}	1.3×10^{-2}
Molybdenum	3.4×10^{-1}	3.4×10^{-1}	1.6×10^{-2}	1.6×10^{-2}
Neodymium	1.3×10^{-1}	1.3×10^{-3}[f]	3.2×10^{-3}	3.2×10^{-3}
Nickel	1.7×10^{-1}	1.7×10^{-2}	4.1×10^{-1}	4.1×10^{-2}
Niobium	5.9×10^{-2}	5.9×10^{-4}	1.4×10^{-3}	1.4×10^{-5}
Osmium	$<2.2 \times 10^{-3}$	$<2.2 \times 10^{-3}$[e]	$<2.6 \times 10^{-1}$	$<2.6 \times 10^{-1}$

(continued)

TABLE 20 (continued)

Pollutant	Emission rate, g/s		Ambient severity	
	Uncontrolled	Controlled	Uncontrolled	Controlled
Elements:				
Palladium	$<1.1 \times 10^{-3}$	$<1.1 \times 10^{-5}$[f]	$<2.6 \times 10^{-5}$	$<2.6 \times 10^{-7}$
Phosphorus	1.0	1.0[e]	2.4×10^{-1}	2.4×10^{-1}
Platinum	$<3.3 \times 10^{-3}$	$<3.3 \times 10^{-5}$[f]	$<4.1 \times 10^{-1}$	$<4.1 \times 10^{-3}$
Potassium	2.5×10^{1}	2.5×10^{-1}	3.0	3.0×10^{-2}
Praeseodymium	2.3×10^{-2}	2.3×10^{-4}[f]	5.6×10^{-4}	5.6×10^{-6}
Rhenium	$<2.2 \times 10^{-3}$	$<2.2 \times 10^{-3}$[e]	$<5.2 \times 10^{-5}$	$<5.2 \times 10^{-5}$
Rhodium	$<1.1 \times 10^{-3}$	$<1.1 \times 10^{-5}$[f]	$<2.6 \times 10^{-3}$	$<2.6 \times 10^{-5}$
Rubidium	4.1×10^{-1}	4.1×10^{-3}	9.7×10^{-3}	9.7×10^{-5}
Ruthenium	$<1.1 \times 10^{-3}$	$<1.1 \times 10^{-5}$[f]	$<2.6 \times 10^{-5}$	$<2.6 \times 10^{-7}$
Samarium	2.1×10^{-2}	2.1×10^{-4}	4.9×10^{-4}	4.9×10^{-6}
Scandium	5.6×10^{-2}	5.6×10^{-4}	1.3×10^{-3}	1.3×10^{-5}
Selenium	5.0×10^{-2}	5.0×10^{-2}	6.0×10^{-2}	6.0×10^{-2}
Silicon	3.0×10^{2}	3.0	7.1	7.1×10^{-2}
Silver	2.8×10^{-4}	2.8×10^{-4}[e]	6.7×10^{-3}	6.7×10^{-3}
Sodium	3.6	3.6×10^{-2}	4.1×10^{-1}	4.1×10^{-3}
Strontium	1.1	1.1×10^{-2}	2.6×10^{-2}	2.6×10^{-4}
Tantalum	1.0×10^{-2}	1.0×10^{-4}	4.9×10^{-4}	4.9×10^{-6}
Tellurium	3.7×10^{-3}	3.7×10^{-3}[e]	9.0×10^{-3}	9.0×10^{-3}
Terbium	3.5×10^{-3}	3.5×10^{-5}	8.6×10^{-5}	8.6×10^{-7}
Thallium	1.1×10^{-3}	1.1×10^{-3}	2.6×10^{-3}	2.6×10^{-3}
Thorium	5.3×10^{-2}	5.3×10^{-4}	1.3×10^{-3}	1.3×10^{-5}
Thulium	$<1.1 \times 10^{-3}$	$<1.1 \times 10^{-5}$[f]	$<2.6 \times 10^{-5}$	$<2.6 \times 10^{-7}$
Tin	2.6×10^{-2}	2.6×10^{-4}	6.3×10^{-4}	6.3×10^{-6}
Titanium	8.9	8.9×10^{-2}	2.1×10^{-1}	2.1×10^{-3}
Tungsten	3.1×10^{-3}	3.1×10^{-3}	7.5×10^{-4}	7.5×10^{-4}
Uranium	1.5×10^{-2}	1.5×10^{-3}	1.8×10^{-2}	1.8×10^{-3}
Vanadium	2.2×10^{-1}	2.2×10^{-2}	1.0×10^{-1}	1.0×10^{-2}
Ytterbium	1.1×10^{-2}	1.1×10^{-4}	2.6×10^{-4}	2.6×10^{-6}
Yttrium	1.2×10^{-1}	1.2×10^{-3}	2.9×10^{-2}	2.9×10^{-4}
Zinc	2.0×10^{-1}	2.0×10^{-1}	9.3×10^{-3}	9.3×10^{-3}
Zirconium	5.5×10^{-1}	5.5×10^{-3}	2.6×10^{-2}	2.6×10^{-4}

[a] Emission height, H = 92.6 m; plume rise, ΔH = 59 m; firing rate = 11 kg/s.

[b] Based on an average ash content of 12.6%.

[c] Based on an average sulfur content of 2.08%.

[d] Not applicable.

[e] Controlled emissions assumed to be equal to uncontrolled emissions based on boiling point of element and/or its oxide.

[f] Controlled emissions assumed to be 1% of uncontrolled emissions based on boiling point of element and/or its oxide.

TABLE 21. EMISSION RATES AND SOURCE SEVERITIES OF THE LARGEST PLANT[a]

Pollutant	Emission rate, g/s		Ambient severity	
	Uncontrolled	Controlled	Uncontrolled	Controlled
Particulate[b]	8.1×10^3	2.0×10^2	5.2	1.3×10^{-1}
NO_x	7.6×10^2	6.0×10^2	1.3	9.8×10^{-1}
SO_x[c]	3.0×10^3	9.0×10^2	1.4	4.1×10^{-1}
CO	3.8×10^{-1}	_[d]	2.7×10^{-4}	_[d]
Hydrocarbons	7.6	_[d]	1.1×10^{-2}	_[d]

[a] Emission height, H = 244 m; plume rise, ΔH = 86 m; firing rate = 75.6 kg/s.

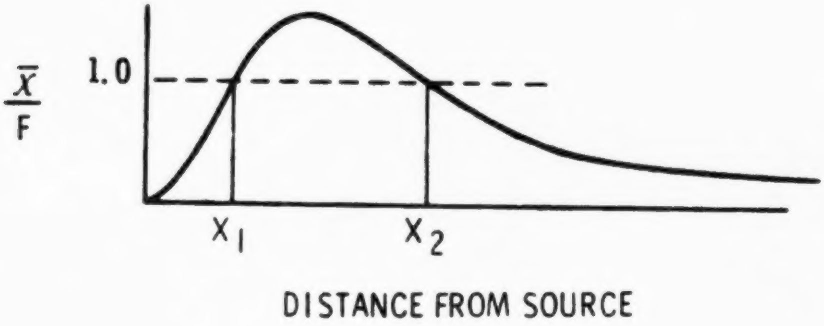
[b] Based on an average ash content of 12.6%.

[c] Based on an average sulfur content of 2.08%.

[d] Not applicable.

Affected Population

Dispersion equations predict that the average ground level concentration, $\overline{X}$, varies with the distance, x, downwind from a source. For elevated sources, $\overline{X}$ is zero at the source (where x = 0), increases to some maximum value, $\overline{X}_{max}$, as x increases, and then falls back to zero as x approaches infinity. Therefore, a plot of $\overline{X}/F$ vs x will have the following appearance.



The affected population is defined as the number of nonplant persons around an average dry bottom utility boiler firing pulverized bituminous coal who are exposed to a $\overline{\chi}/F$ ratio greater than 0.05 or 1.0. An ambient severity of ≥ 1.0 indicates exposure to a potentially hazardous concentration of a pollutant. The ambient severity value of 0.05 allows for inherent uncertainties in measurement techniques, dispersion modeling, and health effects data. The mathematical derivation of the affected population calculation is presented in Appendix C. The number of persons within the exposed area was calculated using a population density of 470 persons/km^2. This value was determined for the average dry bottom industrial boiler firing pulverized bituminous coal [3], and it was assumed that the average utility boiler was similar. Values for the affected population around the average plant are listed in Table 22 for pollutants with severities greater than 0.05. The table indicates that for SO$_x$ and NO$_x$ approximately 300,000 people in the vicinity of the average plant are exposed to pollutant concentrations exceeding 0.05 of the primary ambient air quality standard.

TABLE 22. AFFECTED POPULATION FOR CONTROLLED EMISSIONS WITH A SOURCE SEVERITY GREATER THAN 0.05

Emission species	Affected population for S >0.05, persons
Particulate matter	19,000
NO$_x$	300,000[a]
SO$_x$	320,000[a]
Elements:	
Arsenic	36,000
Chlorine	82,000
Chromium	5,600
Copper	7,700
Fluorine	24,000
Iron	23,000
Lead	81,000
Osmium	<78,000
Phosphorus	70,000
Selenium	8,600
Silicon	13,000

[a] Uncontrolled emissions.

0872
868691

Contribution to Total State and National Emissions

The contributions of emissions from industrial dry bottom boilers firing pulverized bituminous coal to the total emission burdens of the states in which these boilers are located were calculated using state totals of the individual emission estimates presented in the NEDS listing [6]. Controls applied to the boilers in this listing were considered in the estimation of these emissions. Where no values were given for a criteria pollutant in the NEDS for a particular boiler, a value was assigned based on the emission factors in Table 10. Total state and national emissions for the criteria pollutants emitted from stationary sources were obtained from Reference 67.

Table 23 shows the percent contributions of this source category to the five criteria emission burdens for each state in the NEDS listing and to the national totals. The data show that this source type is a major national source of particulates (9.3%), sulfur oxides (44.5%), and nitrogen oxides (25.6%).

AIR EMISSIONS CONTROL TECHNOLOGY

Data from the National Emissions Data System (NEDS) for this source shows that centrifugal collectors (cyclones) and electrostatic precipitators (ESP's) are the principal controls used for air emissions [6]. Approximately 86% of all boilers in this source type are equipped with either cyclones or ESP's, and together these two devices represent 98% of the controls used. Table 24 provides a state-by-state summary of the NEDS data which shows the percentage of boilers controlled and the distribution of controls according to device type. The overall percentage distribution of control devices used for this source is shown in Table 25 [6]; as shown in the table, approximately 17% of the controlled sources included in the NEDS listing use more than one particulate control device, usually a cyclone-ESP combination.

Particulate Controls

Centrifugal collectors and electrostatic precipitators are the most common particulate control devices employed by coal-fired power plants. Although wet scrubbers and fabric filters have not experienced widespread usage, their numbers are increasing in response to new emission regulations. Wet scrubbers are not used primarily for particulate removal with this source but for removal of sulfur oxides.

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[67] Eimutis, E. C., R. P. Quill, and G. M. Rinaldi. Source Assessment: State-by-State Listing of Criteria Pollutants (1978 Update). EPA-600/2-78-004s, U.S. Environmental Protestion Agency, Research Triangle Park, North Carolina, July 1978, 155 pp.

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TABLE 23. TOTAL EMISSIONS AND PERCENT CONTRIBUTIONS TO STATE EMISSION BURDENS FROM DRY BOTTOM UTILITY BOILERS FIRING PULVERIZED BITUMINOUS COAL

State	Total annual emissions from source type [6], metric tons/yr					Total annual emissions from all sources [67], metric tons/yr[a]					Percent of total emissions burden				
	Particulate matter	SO_x	NO_x	Hydrocarbons	CO	Particulate matter[b]	SO_x	NO_x	Hydrocarbons	CO	Particulate matter	SO_x	NO_x	Hydrocarbons	CO
Alabama	177,000	506,000	284,000	3,100	14,000	584,000	832,000	471,000	147,000	3,719,000	30.3	60.8	60.3	2.1	0.4
Alaska	3,300	640	1,200	20	60	30,000	70,000	27,000	18,000	9,000	11.0	0.9	4.5	0.1	0.6
Arizona	5,200	2,500	2,800	50	160	97,000	96,000	50,000	55,000	155,000	5.4	2.6	5.6	0.1	0.1
Colorado	4,200	50,000	38,000	690	2,900	232,000	162,000	119,000	104,000	1,442,000	1.8	30.9	31.8	0.6	0.2
Delaware	1,200	33,000	7,400	120	410	52,000	123,000	44,000	58,000	97,000	2.3	26.8	16.7	0.2	0.4
Florida	20,000	296,000	48,000	760	2,500	522,000	832,000	337,000	233,000	3,113,000	3.8	35.6	14.3	0.3	0.1
Georgia	55,000	489,000	108,000	1,600	6,000	387,000	704,000	293,000	211,000	627,000	14.2	69.4	36.8	0.8	1.0
Illinois	151,000	704,000	118,000	2,000	6,600	1,030,000	1,421,000	570,000	614,000	6,363,000	14.7	49.5	20.7	0.3	0.1
Indiana	71,000	706,000	154,000	2,200	7,200	857,000	1,306,000	477,000	290,000	13,118,000	8.3	54.0	32.3	0.8	<0.1
Iowa	16,000	96,000	18,000	730	1,100	426,000	210,000	108,000	109,000	32,000	3.8	45.7	16.6	0.7	3.4
Kansas	5,200	25,000	5,500	90	310	834,000	106,000	116,000	190,000	91,000	0.6	23.5	4.7	<0.1	0.3
Kentucky	82,000	895,000	173,000	2,200	7,400	326,000	1,197,000	344,000	148,000	1,101,000	25.2	74.8	50.3	1.5	0.7
Maryland	28,000	125,000	35,000	590	2,000	327,000	408,000	176,000	145,000	4,637,000	8.6	30.6	19.9	0.4	<0.1
Massachusetts	5,800	18,000	3,800	60	210	196,000	460,000	187,000	216,000	41,000	3.0	3.9	2.0	<0.1	0.5
Michigan	110,000	963,000	179,000	3,000	10,000	782,000	1,512,000	514,000	321,000	5,376,000	14.1	63.7	34.8	0.9	0.2
Minnesota	14,000	69,000	25,000	430	1,400	408,000	270,000	144,000	160,000	1,089,000	3.4	25.5	17.3	0.3	0.1
Mississippi	3,100	66,000	11,000	190	520	135,000	147,000	89,000	145,000	178,000	2.3	44.8	12.3	0.1	0.3
Missouri	5,800	95,000	24,000	390	1,300	1,002,000	407,000	194,000	224,000	128,000	0.6	23.3	12.4	0.2	1.0
Montana	1,400	7,600	4,800	80	270	932,000	65,000	45,000	63,000	138,000	0.2	11.7	10.6	0.1	0.2
Nebraska	12,000	15,000	8,700	140	480	665,000	55,000	60,000	63,000	40,000	1.8	27.3	14.5	0.2	1.2
Nevada	250	610	5,500	90	300	38,000	56,000	42,000	13,000	14,000	0.6	1.1	13.2	0.7	2.1
New Jersey	8,700	58,000	13,000	200	680	283,000	491,000	269,000	481,000	122,000	3.1	11.8	4.8	<0.1	0.6
New Mexico	20,000	78,000	57,000	470	1,600	93,000	201,000	136,000	97,000	19,000	21.5	38.9	42.0	0.5	8.4
New York	18,000	218,000	92,000	1,800	2,900	793,000	1,268,000	550,000	646,000	3,607,000	2.3	17.2	16.7	0.3	0.1
North Carolina	67,000	363,000	150,000	2,500	8,300	352,000	717,000	348,000	226,000	274,000	19.0	50.6	43.0	1.1	3.0
Ohio	537,000	2,036,000	342,000	5,200	17,000	1,737,000	2,897,000	842,000	546,000	14,393,000	30.9	70.3	40.6	1.0	0.1
Oklahoma	70	30	6	1	2	331,000	62,000	136,000	119,000	180,000	<0.1	<0.1	<0.1	<0.1	<0.1
Pennsylvania	181,000	1,182,000	321,000	4,900	16,000	1,473,000	2,337,000	860,000	716,000	17,894,000	12.3	50.6	37.3	0.7	0.1
South Carolina	13,000	22,000	9,300	160	520	201,000	180,000	191,000	130,000	444,000	6.5	12.2	48.8	0.1	0.1
Tennessee	163,000	884,000	156,000	2,600	8,600	440,000	1,209,000	343,000	159,000	192,000	37.0	73.1	45.4	1.6	4.5
Texas	5,900	30,000	29,000	490	1,600	1,529,000	861,000	941,000	1,825,000	2,322,000	0.4	3.5	3.1	<0.1	0.1
Utah	8,000	23,000	21,000	350	1,200	107,000	98,000	60,000	47,000	854,000	7.5	23.5	35.2	0.7	0.1
Virginia	79,000	56,000	34,000	560	1,900	310,000	342,000	172,000	179,000	198,000	25.5	16.4	19.8	0.3	1.0
Washington	290	10,000	34,000	560	1,900	350,000	337,000	135,000	172,000	312,000	0.1	3.0	25.2	0.3	0.6
West Virginia	66,000	648,000	273,000	3,300	10,000	380,000	1,114,000	482,000	135,000	2,156,000	17.4	58.1	56.6	2.4	0.5
Wisconsin	74,000	282,000	60,000	970	3,300	400,000	593,000	209,000	177,000	113,000	18.5	47.6	28.8	0.5	2.9
Wyoming	28,000	49,000	44,000	900	3,000	120,000	155,000	93,000	92,000	27,000	23.3	31.5	47.2	1.0	11.1
United States	2,040,000	11,103,000	2,890,000	44,000	183,000	21,876,000	25,010,000	11,305,000	11,627,000	89,205,000	9.3	44.5	25.6	0.4	0.2

[a] Adjusted for new emission totals from this source type. Does not include mobile sources.

[b] Excluding emissions from unpaved roads.

TABLE 24. STATE-BY-STATE SUMMARY OF EMISSION CONTROLS DATA IN NEDS FOR DRY BOTTOM UTILITY BOILERS BURNING PULVERIZED BITUMINOUS COAL [6]

State	Total number of sources	Number of controlled sources	Percent controlled	Number of single control devices				Number of sources with more than one particulate control device
				Electrostatic precipitator	Centrifugal collector	Wet scrubber	Fabric filter	
Alabama	20	20	100	13	6			1
Alaska	1	1	100		1			
Arizona	1	1	100		1			
Colorado	18	17	94	9	2			6
Deleware	3	3	100					3
District of Columbia	2	2	100	1				1
Florida	14	14	100	12	2			
Georgia	28	28	100	27			1	
Illinois	68	48	71	33	10	4		1
Indiana	53	51	96	44	5			2
Iowa	25	22	88	13	9			
Kansas	6	6	100	3	2	1		
Kentucky	47	47	100	24	23			
Maryland	10	10	100	10				
Massachusetts	2	2	100		2			
Michigan	78	55	75	28	1	1		25
Minnesota	17	15	88	7	6	1		1
Mississippi	3	3	100	3				
Missouri	11	10	91	1	7	2		
Montana	1	1	100	1				
Nebraska	13	13	100		8			5
Nevada	2	2	100					2
New Jersey	7	5	71	5				
New Mexico	6	6	100	2		3		1
New York	50	50	100	26	7			17
North Carolina	44	41	93	34	4			3
Ohio	110	106	96	58	19			29
Oklahoma	3	0	0					
Pennsylvania	109	78	72	48	10			20
South Carolina	12	5	42	4	1			
Tennessee	32	32	100	8	13			11
Texas	2	2	100	2				
Utah	10	10	100	2	2			6
Virginia	9	9	100	1	8			
Washington	2	2	100					2
West Virginia	31	31	100	11	20			
Wisconsin	41	40	98	32	8			
Wyoming	11	10	91	3	5	1		1
Total	902	798	88	465	182	13	1	137

Note: Blanks indicate that no devices of the type specified appeared in the NEDS listing for that state.

TABLE 25. DISTRIBUTION OF CONTROL TYPES FOR THOSE DRY BOTTOM UTILITY BOILERS BURNING PULVERIZED BITUMINOUS COAL HAVING CONTROLS [6]

Type of control device	Percent of controls in use
Centrifugal collector	23
Electrostatic precipitator	58
Wet scrubber	2
Fabric filter	<1
Dual control[a]	17

Breakdown of dual controls used

Dual control system	Percent of dual controls in use
Centrifugal collector and wet scrubber	1
Centrifugal collector and ESP	77
ESP and ESP	18
ESP and wet scrubber	4

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[a] Two separate control devices used in series.

Centrifugal Collectors--

As shown in Table 25, dry cyclones are used extensively to collect fly ash generated by this source type. In the basic cyclone collector, the entire mass of the gas stream with the entrained particulate matter is forced into a constrained vortex, achieved by means of fixed internal vanes, in the cylindrical portion of the cyclone. By virtue of their rotation with the carrier gas around the axis of the tube and their higher density with respect to the gas, the entrained particles are forced toward the wall by centrifugal force and carried away by gravity and/or secondary eddies toward the outlet at the bottom of the tube. The flow vortex is reversed in the lower portion of the tube, leaving most of the entrained particles behind. The cleaned gases then pass through the central, or exit, tube and out of the collector.

Particle size, weight, and shape, and the gas flow rate affect the forces on the particles entering the collector and thus affect collection efficiency. Larger and denser particles are easier to collect; higher flow rates increase collection efficiency. For boilers burning pulverized coal, the average collection efficiency is about 90% [68].

Although centrifugal collectors are the least expensive and most reliable primary collection devices for particulates, they are no longer acceptable in many areas because of their low collection efficiencies. In other applications, they can be used as precleaning units for precipitators, scrubbers, and fabric filters. Current design improvement efforts are directed toward increasing the collection efficiencies of centrifugal collectors through reduced reentrainment and improved gas flow distribution.

Electrostatic Precipitators--

An electrostatic precipitator (ESP) separates particles and mists from gases by passing the gas stream between two electrodes across which a unidirectional, high-voltage (20 kV to 80 kV DC) potential is affected. The particles pass through this field, becoming charged and migrating to the oppositely charged electrode. Collected particles remain on the charged electrode until removed, and the gas which has thus been cleaned moves on to recovery or exhaust. Periodic vibration of the collecting electrode surface causes the dust to drop into hoppers for removal.

Very high collection efficiencies can be achieved using ESP's; most new units are rated at 99% or higher. Generally, collection efficiencies are reduced as particle size decreases and gas flow rate increases. The electrical resistivity of the fly ash is also important; decreased resistivity improves collection efficiency. Flue gas temperature plays a major role in determining fly ash resistivity; resistivity increases as the temperature increases from ambient conditions (∿25°C) to about 150°C to 200°C. A further increase in temperature causes fly ash resistivity to fall. The actual shape of the resistivity-temperature curve depends on the chemical composition of the fly ash and the water vapor and SO_3 in the flue gas. In general, an increase in coal sulfur content (leading to more SO_3 in the flue gas) or alkali metal content (leading to higher alkali metal concentrations in the fly ash) will cause a decrease in fly ash resistivity and enhance collection efficiency [69].

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[68] Jones, A. H. Air Pollution Control for Industrial Coal-Fired Boilers. In: Power Generation: Air Pollution Monitoring and Control, K. E. Noll and W. T. Davis, eds. Ann Arbor Science Publishers, Inc., Ann Arbor, Michigan, 1976. pp. 529-542.

[69] White, H. J. Electrostatic Precipitation of Fly Ash. Journal of the Air Pollution Control Association, 27:15-21, 114-200, 206-217, 308-318, 1977.

When fly ash resistivity exceeds a critical value of about 10^{10} ohm-cm, precipitator performances begins to decline rapidly. Because low sulfur coals often have resistivities above this level, electrical utilities may install ESP's before air preheaters (hot side installation) where higher flue gas temperatures (300°C to 400°C) result in acceptable resistivities (i.e., less than 10^{10} ohm-cm). Cold side ESP's located after the air preheater have traditionally been employed for higher sulfur coals. Flue gas temperatures after the preheater range from 125°C to 170°C. These lower temperatures offer the advantages of a lower volume of flue gas to treat and fewer of the mechanical and electrical problems associated with hot side operations [69, 70].

Fabric Filters--

In fabric filters, particles in the flue gas are mechanically filtered out by tube-like cloth bags located in a baghouse (enclosing structure). Removal of the trapped particles is accomplished by shaking the bag, reversing the air flow, or rapidly expanding the bags using compressed air. Chief drawbacks of fabric filters are the high pressure drop required and the short life-span of many bag materials.

Fabric filters are the most promising technology for controlling small (submicron) particulate matter. They can be extremely efficient; removal efficiencies have been reported in the range of 99.9% [71]. Application of fabric filters to utility boilers has been limited because they are generally more expensive than ESP's.

Wet Scrubbers--

Wet scrubbers use water or other liquids as the scrubbing agent to remove particles and absorb gaseous emissions from combustion gases. The liquid containing the pollutants is then separated from the gas stream. Because scrubbers are less efficient than ESP's or fabric filters in removing particulate matter, they have had only limited use in the past on coal-fired utility boilers. With the advent of more stringent SO_x emission limitations, the use of scrubbers is expected to increase.

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[70] Baxter, W. A. Electrostatic Precipitator Design for Western Coals. In: Power Generation: Air Pollution Monitoring and Control, K. E. Noll and W. T. Davis, eds. Ann Arbor Science Publishers, Inc., Ann Arbot, Michigan, 1976. pp. 415-425.

[71] Forester, W. D. Future Bright for Fabric Filters. Environmental Science and Technology, 8(6):508, 1974.

085981
085959

There are two categories of scrubbers: low energy (pressure drop of 750 Pa to 3,700 Pa [3 to 15 inches of water]) and high energy (pressure drop of 3,700 Pa to 25,000 Pa [15 to 100 inches of water]). Numerous scrubber configurations are used for low energy units. Venturi type scrubbers are used in installations requiring high-energy collection of submicron particles. The unique shape of the Venturi offers 98% velocity head (power consumption) recovery, thereby allowing efficient introduction of fluid to meet the gas crossflow in the throat region.

Sulfur Oxides Control

Recently revised New Source Performance Standards for coal-fired utility boilers require some form of sulfur oxide control even for low sulfur coals. However, the degree of control needed is less for low sulfur coals [49].

SO_x Control by Use of Low-Sulfur Coal--

Sulfur oxide emissions from coal-fired boilers are directly related to the sulfur content of the coal. A decrease in sulfur content results in a corresponding reduction in emissions. Low-sulfur coal can be obtained from naturally occurring deposits or through the physical cleaning of coal high in pyritic sulfur.

Supplies of low-sulfur, high quality, eastern coal are limited. Western coal, with its generally low heating value and higher moisture content than Eastern coal, must be used in greater tonnage to meet a given steam output. Boilers operating near design capacity and burning alternate Western coal could not meet original load requirements without extensive modification. It has been estimated that supplies of low-sulfur coal will meet only 44% of the demands in 1980 [72].

Physical cleaning (beneficiation) of coal removes up to 80% of the inorganic pyritic and sulfate sulfur; however, it does not remove the organic sulfur which can account for 20% to 85% of the sulfur present [72]. Beneficiation is accomplished by crushing the coal and separating the heavier pyrite-bearing particles using techniques which utilize particle density differences. It is estimated that only about 17% of the coal presently mined in the United States can be adequately cleaned with this procedure [73]. In the remaining coal, either the ratio of organic sulfur to inorganic sulfur is too high or the sulfur content is too low to permit economic handling. Research is underway to develop improved cleaning techniques for removing sulfur from coal, i.e., through chemical treatment.

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[72] Green, R. Utilities Scrub Out SO_x. Chemical Engineering, 84(11):101-103, 1977.

[73] Davis, J. C. Coal Cleaning Readies for Wider Sulfur-Removal Role. Chemical Engineering, 83(5):70-74, 1976.

SO_x Control by Use of Flue Gas Desulfurization (FGD)--

Sulfur oxides are removed from flue gas by absorption and/or chemical reaction using a solid or liquid phase. Presently, about two dozen FGD processes at various stages of development are being evaluated in the United States. These processes are classified as nonregenerable or regenerable, depending on the fate of the reactive component of the absorbent. Nonregenerable processes produce a sludge consisting of fly ash, water, and sulfate/sulfite salts which must be discarded. In regenerable processes, the sulfur is recovered and converted into marketable products such as elemental sulfur, sulfuric acid, or concentrated sulfur dioxide; the absorbent is regenerated and recycled.

The nonregenerable processes, which are developed farther and used more than the regenerable processes, account for 94% (by capacity) of all FGD systems applied to utility boilers. Lime scrubbing and limestone scrubbing represent the major nonregenerable processes in commercial use on utility boilers. The most popular regenerable process is the Wellman-Lord process. Table 26 summarizes the results of a recent survey of FGD systems applied to utility boilers [74].

Numerous process descriptions of the various FGD systems being marketed or under development are available in the literature [75-82]. Descriptions of the utility boiler SO_x scrubbers currently in use or under construction and available operating experience is presented in Reference 74.

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[74] Smith, M., M. Melia, T. Koger, R. McKibben, and J. Uihlein. EPA Utility FGD Survey: December 1978 - January 1979. EPA-600/7-79-022c (PB 299 399), U.S. Environmental Protection Agency, Washington, D.C., May 1979. 453 pp.

[75] The McIlvaine Scrubber Manual. The McIlvaine Co., Northbrook, Illinois, 1976.

[76] Selmeczi, J. G., and D. A. Stewart. The Thiosorbic Flue Gas Desulfurization Process. Chemical Engineering Progress, 74(2):41-45, 1978.

[77] Idemura, H., T. Kanai, and H. Yanagioka. Jet Bubbling Flue Gas Desulfurization. Chemical Engineering Progress, 74(2): 46-50, 1978.

[78] Grimm, C., J. Z. Abrams, W. W. Leffmann, I. A. Raben, and C. LaMantia. The Colstrip Flue Gas Cleaning System. Chemical Engineering Progress, 74(2):51-57, 1978.

[79] Princiotta, F. T. Advances in SO_2 Stack Gas Scrubbing. Chemical Engineering Progress, 74(2):58-64, 1978.

(continued)

TABLE 26. UTILITY BOILERS FGD SYSTEMS [74]

Process	Number of systems	Capacity, MW	Status
Lime	16	5,798	Operational
	11	4,958	Under construction
Limestone	17	6,748	Operational
	22	8,206	Under construction
Lime/alkaline fly ash	1	405	Operational
	4	1,054	Under construction
Limestone/alkaline fly ash	2	1,480	Operational
Lime/limestone	2	20	Operational
	1	358	Under construction
Sodium carbonate	3	375	Operational
	1	550	Under construction
Limestone/Chiyoda 121	1	23	Operational
Dual alkali	3	1,170	Under construction
Aqueous carbonate/spray drying	1	440	Under construction
Wellman Lord[a]	3	826	Operational
	1	180	Under construction
Magnesium oxide[a]	1	120	Operational
Citrate[a]	1	60	Under construction
Total	46	15,795	Operational
	45	16,976	Under construction

[a] Regenerable processes.

Nitrogen Oxides Control

Current applications of NO_x controls to coal-fired utility boilers in the United States involve various types of combustion modification. Although NO_x control by flue gas treatment is not practiced in this country, it is used elsewhere and may be needed in the future to meet more restrictive standards.

NO_x Control by Combustion Modification--

Current stationary source NO_x emission standards and those envisioned for the near future are based on combustion modification techniques. In the temperature range used in dry bottom boilers, thermal formation of NO_x from atmospheric nitrogen does not make a large contribution to total NO_x emissions. Therefore, the most effective combustion modification techniques focus on reducing the oxidation of fuel nitrogen. The major factors influencing the formation of NO_x from fuel nitrogen are oxygen concentration, fuel nitrogen content, temperature, and residence time [30-44, 52, 83-85].

(continued)

[80] Rochelle, G. T., and C. J. King. Alternatives for Stack Gas Desulfurization by Throwaway Scrubbing. Chemical Engineering Progress, 74(2):65-70, 1978.

[81] Slack, A. V. Lime-Limestone Scrubbing: Design Considerations. Chemical Engineering Progress, 74(2):71-75, 1978.

[82] Raymond, W. J., and A. G. Sliger. The Kellogg/Weir Scrubbing System. Chemical Engineering Progress, 74(2):75-80, 1978.

[83] Mason, H. B., and L. R. Waterland. Environmental Assessment of Stationary Source NO_x Combustion Modification Technologies. In: Proceedings of the Second Stationary Source Combustion Symposium; Volume I: Small Industrial, Commercial, and Residential Systems. EPA-600/7-77-073a (PB 270 923), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, July 1977. pp. 37-82.

[84] Armento, W. J., and W. L. Sage. Effect of Design and Operation Variables on NO_x Formation in Coal-Fired Furnaces: Status Report. In: Air - II. Control of NO_x and SO_x Emissions, AIChE Symposium Series, 71(148):63-70, 1975.

[85] England, C. and J. Houseman. NO_x Reduction Techniques in Pulverized Coal Combustion. In: Proceedings, Coal Combustion Seminar. EPA-650/2-73-021 (PB 224 210), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, September 1973. pp. 173-190.

Reduction of NO_x from fuel bound nitrogen can be accomplished by providing a fuel rich environment for combustion to occur. A simple model of the nitrogen to NO_x conversion process was developed, based on experimental data in which 1) the conversion efficiency is inversely proportional to the weight fraction of nitrogen in the fuel and 2) the conversion efficiency is linearly proportional to the local air-fuel ratio, with zero NO_x occurring when there is just sufficient oxygen present to oxidize the fuel carbon to carbon monoxide and the fuel hydrogen to water [86, 87].

Two successful approaches have been used to achieve fuel rich combustion, thereby lowering NO_x emissions from coal-fired boilers. These are 1) the reduction of the amount of excess air fired and 2) staged combustion. Excess air refers to air added to a furnace in excess of that required for stoichiometric combustion. Various studies on coal-fired utility boilers have shown that reduction in the amount of excess air being fired is the best method for changing primary flame zone conditions considering such factors as ease of implementation, emission reduction, and effect on boiler efficiency [52, 84]. NO_x emissions decreased an average to 50 ppm for each 1% reduction in excess air; a total reduction of 38% from the baseline NO_x emissions was found to be attainable. Low excess-air operation improves boiler efficiency and does not increase particulate emissions as do some other modifications.

Staged combustion describes a combustion modification technique in which the lower level (or upstream) burners in a furnace are fired with a fuel rich air/fuel mixture. The remainder of the combustion air necessary to achieve complete combustion is then added via the upper level (or downstream) burners. Combustion thus occurs in two distinct stages, the first one being a fuel rich stage where very little NO_x can form from the fuel nitrogen. The second stage attains a stoichiometric fuel/air ratio, but the flame temperature and residence time are conducive to lower levels of NO_x production. It has also been postulated that, in the fuel rich region, fuel nitrogen is initially converted to NO. However, in the presence of unreacted carbon and hydrogen, NO is

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[86] Dykema, O. W. Analysis of Test Data for NO_x Control in Coal-Fired Utility Boilers. EPA-600/2-76-274 (PB 261 066), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, October 1976. 100 pp.

[87] Dykema, O. W. Combustion Modification Effects on NO_x Emissions from Gas-, Oil-, and Coal-Fired Utility Boilers. EPA-600/2-78-217 (PB 289 898). U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, December 1978. 97 pp.

reduced to stable nitrogen compounds such as N_2 [52, 87]. Staged combustion has been shown to yield substantially lower NO_x levels (50% decrease or more from baseline conditions, achieving below 200 ppm NO_x in the exit gas concentration). However, fuel rich operation may create problems of combustion instability and boiler corrosion, if carried out to excessive levels (40% or more of the combustion air diverted to the second stage) [87].

NO_x Control by Flue Gas Treatment--

Should more stringent standards be promulgated for NO_x emissions, flue gas treatment may be required for NO_x emission reduction. Hence, experimental flue gas treatment projects are progressing toward full-scale demonstration of highly efficient control technology for NO_x and NO_x/SO_x emissions. These technologies, imported from Japan, are classified as wet or dry processes.

Dry flue gas treatment processes being developed include the following [88]: 1) selective catalytic reduction, 2) selective noncatalytic reduction, 3) adsorption, 4) nonselective catalytic reduction, 5) catalytic decomposition, and 6) electron beam radiation. Of these, only selective catalytic reduction has achieved notable success in treating flue gas and progressed to the point of being commercially applied [88]. Selective catalytic reduction is based on the reduction of NO_x compounds to N_2 by reaction with ammonia. Two variations of selective catalytic reduction are capable of removing both SO_x (∿90% efficient) and NO_x (70% to 90% efficient). The other dry processes are much less attractive at present due to their low NO_x removal efficiencies, nonapplicability to combustion sources, or early stage of development.

Wet flue gas treatment processes under development include the following [88]: 1) oxidation-absorption, 2) absorption-oxidation, 3) oxidation-absorption-reduction, and 4) absorption-reduction. The first two processes listed are generally used only for NO_x control. In oxidation-absorption, relatively insoluble nitrogen oxide (NO) is oxidized in the gas phase to nitrogen dioxide (NO_2) which is absorbed into the liquid phase. In absorption-oxidation, NO is absorbed directly into the liquid phase and then oxidized.

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[88] Mobley, J. D., and R. D. Stern. Status of Flue Gas Treatment Technology for Control of NO_x and Simultaneous Control of SO_x and NO_x. In: Proceedings of the Second Stationary Source Combustion Symposium; Volume III: Stationary Engine, Industrial Process Combustion Systems, and Advanced Processes. EPA-600/7-77-073c (PB 271 757), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, July 1977. pp 229-251.

The last two processes listed above are designed to remove SO_x and NO_x; they are basically modifications of existing flue gas desulfurization processes. Due to their complexity, limited applicability, and water pollution problems, wet processes can not compete economically with the dry selective catalytic reduction process.

Control of Other Air Emissions

Separate controls for other emission species (e.g., POM's and trace elements) are nonexistent on coal-fired utility boilers. However, control devices or techniques that reduce emissions of criteria pollutants may be effective in controlling other emissions as well. Thus, particulate control devices capture any POM's or trace elements present in a condensed phase. It is also possible that techniques such as combustion modification for NO_x control may lead to an increase in emissions such as POM's [83].

SECTION 5

WASTEWATER EFFLUENTS AND CONTROL TECHNOLOGY

SOURCES AND CHARACTERISTICS

Water usage in steam electric generating facilities is complex and results in a number of wastewater effluents. Most of the required water is used for steam generation, cooling, equipment cleaning, and ash transport. Effluents linked with these uses contain: 1) ash and other coal combustion products; 2) chemicals added on site such as biocides, corrosion inhibitors, and cleaning agents; and 3) water treatment wastes containing treatment chemicals and the pollutants present in the water supply. Total suspended solids (TSS), iron, copper, hardness, and sulfate are the principal pollutants found in coal-fired boiler effluents [2].

Wastewater quantities and, to a lesser extent, wastewater qualities associated with the operation of coal-fired utility boilers vary with the operating practices employed. The major factors responsible for this variation are listed below:

- Cooling water for steam condensation may be used once and discharged or recirculated.

- Ash may be handled dry, or water slurried and sent to ash ponds.

- Depending on the quality of the water supply, a number of water treatment processes are available for preparing boiler feed water; each process generates different quantities and qualities of wastewater.

- Numerous chemical additives (shown in Table 27) containing a wide variety of active ingredients are available for use as oxygen scavengers, scale and corrosion inhibitors, biocides, water treatment chemicals, dispersing agents, cleaning agents, and for pH control [16].

Table 28 summarizes various boiler wastewater effluents and the major pollutants and pollutant parameters applicable to each stream [16]. A brief description of each waste stream is presented in the following paragraphs. Effluent data are also given

TABLE 27. CHEMICAL ADDITIVES USED IN STEAM ELECTRIC POWER PLANTS [16]

Use	Chemical
Coagulant in clarification water treatment	Aluminum sulfate Sodium aluminate Ferrous sulfate Ferric chloride Calcium carbonate
Regeneration of ion exchange water treatment	Sulfuric acid Caustic soda Hydrochloric acid Common salt Soda ash Ammonium hydroxide
Lime soda softening water treatment	Soda ash Lime Activated magnesia Ferric salts Dolomitic lime
Corrosion inhibition or scale prevention in boilers	Disodium phosphate Trisodium phosphate Sodium nitrate
pH control in boilers	Ammonia Cyclohexylamine
Sludge conditioning	Tannins Lignins Chelates such as ethylenediaminetetraacetic acid, nitrilotriacetic acid
Oxygen scavengers in boilers	Hydrazine Morphaline
Boiler cleaning	Hydrocloric acid Citric acid Formic acid Hydroxyacetic acid Potassium bromate Phosphates Thiourea Hydrazine Ammonium hydroxide Sodium hydroxide Sodium carbonate Nitrates
Regenerants of ion exchange for condensate treatment	Caustic soda Sulfuric acid
Corrosion inhibition or scale prevention in cooling towers	Organic phosphates Sodium phosphate Chromates Zinc salts Synthetic organics
Biocides in cooling towers	Chlorine Hydrochlorous acid Sodium hypochlorite Calcium hypochlorite Organic chromates Organic zinc compounds Chlorophenates Triocyanates Organic sulfurs
pH control in cooling towers	Sulfuric acid Hydrochloric acid
Dispersing agents in cooling towers	Lignins Tannins Polyacrylonitrile Polyacrylamide Polyacrylic acids Polyacrylic acid salts
Biocides in condenser cooling water systems	Chlorine Hypochlorites
Additives to house service water systems	Chlorine Chromates Caustic soda Borates Nitrates
Numerous uses	Numerous proprietary chemicals

TABLE 28. POLLUTANTS AND POLLUTANT PARAMETERS ASSOCIATED WITH VARIOUS BOILER WASTEWATER EFFLUENTS [16]

	Condenser cooling systems		Water treatment processes				Chemical cleaning						
Parameter	Once-through	Recirculating	Clarification wastes	Ion-exchange wastes	Evaporator blowdown	Boiler blowdown	Boiler tubes	Air preheater	Boiler fireside	Ash pond overflow	Coal pile drainage	Floor drains	Air pollution devices SO_2 removal
Alkalinity	X	X	X	X	X	X	X	X	X	X			X
BOD[a]		X	X	X	X	X	X	X		X		X	X
COD[b]		X	X	X	X	X	X	X	X	X		X	
TS[c]	X	X	X	X	X	X	X	X	X	X	X	X	X
TDS[d]	X	X	X	X	X	X	X	X	X	X	X	X	X
TSS[e]		X	X	X	X	X	X	X	X	X	X	X	X
Ammonia		X	X	X	X	X	X	X	X	X	X		
Nitrate		X	X	X	X	X	X			X	X		
Phosphorous		X	X	X	X	X	X			X	X		X
Turbidity		X	X		X	X	X	X	X	X	X	X	X
Acidity							X	X	X	X	X	X	X
Hardness		X	X	X	X	X	X			X		X	X
Sulfate		X	X	X	X	X	X	X	X	X	X	X	X
Sulfite								X	X	X		X	X
Bromide							X						
Chloride		X	X		X	X	X	X	X	X	X		
Fluoride		X	X	X			X			X			
Aluminum		X	X		X	X	X		X	X	X		X
Boron													
Chromium		X	X	X	X	X	X	X	X	X	X		
Copper	X	X	X	X	X	X	X	X	X	X	X		
Iron		X	X	X	X	X	X	X	X	X	X		X
Lead										X	X	X	
Magnesium		X	X	X	X	X	X	X	X	X	X	X	X
Mercury				X	X		X			X	X		
Nickel		X	X	X	X	X	X	X	X	X	X		
Selenium							X			X	X		
Vanadium									X	X			X
Zinc		X	X	X	X	X	X			X	X		
Oil and grease				X			X			X		X	X
Phenols		X	X		X					X	X		
Surfactants					X		X			X		X	
Algicides	X	X											
Chlorine	X	X											
Manganese		X		X	X	X	X		X	X	X		X

[a] BOD = biochemical oxygen demand.

[b] COD = chemical oxygen demand.

[c] TS = total solids.

[d] TDS = total dissolved solids.

[e] TSS = total suspended solids.

as obtained by EPA and its contractors pursuant to the establishment of effluent limitations guidelines for the industry. It should be noted that data for some wastewater streams includes measurements for coal-, oil-, and gas-fired plants because the wastewater composition is independent of the fuel type.

Waste Streams from the Condenser Cooling System

The condenser cooling system condenses spent steam (from expansion in the turbine generator to produce electricity) so it may be recycled to the boiler or discharged. Either a once-through or a recirculating system may be used.

Once-through cooling systems use cooling water only one time and then discharge it. Because of the large volume of water used, treatment of the influent is minimized, and the effluent is not ususally treated prior to discharge. Treatment of influent water for once-through cooling usually entails intermittent doses of a biocide such as chlorine or a hypochlorite. The frequency and duration of biocide treatments vary from plant to plant. They may be applied from once per day up to as many as ten times per day, and the duration of treatment varies between 5 minutes and 2 hours resulting in residual chlorine concentrations in the range of 0.1 g/m^3 to 1 g/m^3 [16]. In addition to any chemicals added to the system, the cooling-water discharge will contain particles resulting from corrosion and erosion of the condenser tubes.

If the steam generating plant is not located near a large body of water, a once-through cooling system is impractical, and a recirculating system must be installed to minimize water costs and discharges. Recirculating systems discharge their waste heat through evaporation of some of the recirculating water in a cooling tower or pond. During evaporation, water vapor is removed and some entrainment of droplets in the air draft (drift) occurs; hence, the salts dissolved in the cooling water become more concentrated. To limit the concentrations of dissolved solids and to prevent their deposition on heat transfer surfaces, some water must be removed as blowdown. The rate of blowdown depends on the quality of the make-up water and the permissible concentration factor for a particular system. Unless limited by a specific discharge permit, the concentration factor is based on that required to protect plant equipment from scaling, fouling, corrosion, or excessive deposits. Blowdown rates range from 0.1% of the circulating water flow for high-quality, make-up water to as much as 5.0% for brackish water [89].

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[89] Assessment of the Costs and Capabilities of Water Pollution Control Technology for the Steam Electric Power Industry. NCWQ 75/86 (PB 251 372), National Commission on Water Quality, Washington, D.C., March 1976. 1164 pp.

Pollutants found in cooling water blowdown consist of 1) a concentration of the species found in the water source, 2) air pollutants absorbed or entrained in the cooling water while in the tower, which acts as a wet scrubber for the ambient air, and 3) chemicals added for various purposes. Condenser materials are generally chosen to resist corrosion; thus special chemicals for corrosion control are not required unless the influent is high in chlorides. Table 29 contains effluent data for cooling system wastewater concentrations [90]. Data was obtained from coal-, oil-, and gas-fired plants.

Waste Streams from Water Treatment Processes

Because all water supplies contain some suspended solids and dissolved chemical salts, boiler feedwater is treated to prevent scale formation. The basic treatment processes used are clarification, filtration, lime/lime soda ash softening, ion exchange, reverse osmosis and evaporation (without reverse osmosis).

Clarification agglomerates suspended solids allowing them to settle. The sludges are raked from the settling basin bottom and removed to a sludge pond. Chemicals such as aluminum sulfate, ferrous sulfate, ferric sulfate, sodium aluminate, polyelectrolytes, and others are used as agglomerants. Wastewater streams from clarifiers usually contain 3,000 g/m^3 to 15,000 g/m^3 total solids (of which 75% to 80% are suspended solids and the remainder volatile solids), 30 g/m^3 to 100 g/m^3 BOD, 500 g/m^3 to 10,000 g/m^3 COD, and pH of 5 to 9.

In the softening process, ions causing hardness (Ca^{2+} and Mg^{2+}) are precipitated and removed as sludge. The two major chemicals used are calcium hydroxide (lime) and sodium carbonate (soda ash). Soda ash causes the precipitation of calcium carbonate and the formation of magnesium carbonate. Partially soluble magnesium carbonate reacts with lime to form insoluble magnesium hydroxide. Sludges produced from softening are discussed in Section 6 which covers solid wastes.

In the ion-exchange process, resins selectively remove cations and anions from feed water, replacing cations with hydrogen or sodium and anions with hydroxide ions. When the exchange capacity of a resin has been met, the resin must be regenerated resulting in the production of wastewater. Regeneration is a three-stage process consisting of a backwash to remove solids from the bed; a chemical contact step which releases impurities from the resin while recharging it with hydrogen, sodium, or hydroxide ions; and a rinse to remove the impurities along with

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[90] Draft Technical Report for Revisions of Steam Electric Effluent Limitations Guidelines. U.S. Environmental Protection Agency, Washington, D.C., September 1978. 607 pp.

TABLE 29. POLLUTANTS IN COOLING WATER DISCHARGE [90]

Pollutant	Once through cooling water systems[a]: Intake: Number of plants	Intake: Concentration[d] Range	Intake: Concentration[d] Median	Discharge: Number of plants	Discharge: Concentration[d] Range	Discharge: Concentration[d] Median	Recirculating cooling water system[b,c]: Intake: Number of plants	Intake: Concentration[d] Range	Intake: Concentration[d] Median	Discharge: Number of plants	Discharge: Concentration[d] Range	Discharge: Concentration[d] Median
Classical parameters												
BOD_5											39 - 10,400	4,000
COD											450 - 103,000	25,000
Oil and grease											43 - 7,430	2,200
Phosphate (total)											60 - 3,250	520
Total dissolved solids											886,000 - 5,110,000	1,900,000
Total suspended solids											2,900 - 59,000	18,000
Total solids											889,000 - 5,170,000	,920,000
Toxic pollutants												
Antimony	3	<5 - 7	<5	3	<5 - 10	<5	2	4 - 7	6	3	BDL - 7	5
Arsenic					<5 - 25	15[e]	3	BDL - 3	1	3	4 - 35	7
Asbestos						BDL[e]	18	BDL - 140,000	BDL	14	BDL - 160,000,000	BDL
Beryllium	3		<5	3		<5	2	BDL - <10		4	BDL - <10	3.4
Cadmium	3	<5 - <10	<5	3	<5 - 30	<5	7	BDL - 100	8	8	BDL - 200	3
Chromium	3	<5 - 39	24	3	<5 - 17	8	8	BDL - 439	70	8	2 - 555	52
Copper	3	6 - 22	16	3	5 - 24	20	8	9 - 700	32	8	34 - 3,800	56
Cyanide	3	<20 - 20	<20	3	<20 - 20					6	BDL - <20	<20
Lead	3	<5 - 19	8	3	<5 - 14	<5	7	6 - 500	20	7	BDL - 800	<20
Mercury	3	0.21 - 0.42	0.23	3	0.17 - 0.42	0.34				3		BDL
Nickel	3	<5 - 29	7	3	<5 - 26	25	7	1.5 - 200	5	8	4 - 200	18
Selenium	3	11 - 35	20	3	<5 - 28	18				3		[illegible]
Silver	3	<5 - 12	<5	3		<5	6	BDL - 40	1.3	6	0.7 - 80	3
Thallium	3		<5	3	<5 - 13	<5	1		BDL	3	BDL - 8	BDL
Zinc	3	<5 - 42	5	3	<5 - 20	<5	6	15 - <600	62	6	26 - 700	240
Phthalates												
Bis(2-ethylhexyl) phthalate	1		10	4	12 - 25	11	1		21	5	<10 - 36	44
Butyl benzyl phthalate				1		10						
Di-n-butyl phthalate	3	<10 - 30	23	5	23 - 46	26	4	30 - 60	37	5	<10 - 48	10
Diethyl phthalate				2	10 - 11	11						
Di-n-octyl phthalate				1		10						
Phenols												
Phenol (total)	3	<10 - <100	30	3	<10 - <100	50						
2,4-Dichlorophenol							2		<25			
2,4-Dinitrophenol							1		<25			
Pentachlorophenol							2		<25			
Phenol	4	5 - 15	10	4	5 - 18	7	3	7 - 16	12	3	8 - 10	8
2,4,6-Trichlorophenol	1		20	1		<25	3		<25	1		35
Aromatics												
Benzene										1		65
1,2-Dichlorobenzene	1		10	2	10 - 30	20	3	<10 - 18	<10	3	<10 - 26	20
1,3-Dichlorobenzene	1		10	2	10 - 30	20	3	<10 - 18	<10	3	<10 - 26	20
1,4-Dichlorobenzene	1		10	2	10 - 30	20	3	<10 - 18	<10	3	<10 - 26	20
1,2,4-Trichlorobenzene				1		10						
Polycyclic aromatic hydrocarbons												
2-Chloronaphthalene				1		10						
Halogenated aliphatics												
Bromoform	1		<10	1	97 - 580	300	1		BDL	2	13 - 150	82
Chlorodibromomethane							1		BDL	1		59
1,2-Dichloroethane	1		72	1		44						
1,1-Dichloroethylene				1		16						
1,2-*Trans*-dichloroethylene				1		11						
Methylene chloride	1		200	6	2,000 - 9,400	<3,000	1		76	6	65 - 9,400	1,600
Tetrachloroethylene				1		78						
1,1,1-Trichloroethane				1		12				2	13 - 26	18

[a] Metals concentrations are screening data; verification results not available. Organics derived from verification data.

[b] Cooling tower blowdown.

[c] Verification data.

[d] Values in mg/m³ except for asbestos values, which are in fibers/liter.

[e] Based on less than three data points.

Note: Blanks indicate data not available.
BDL = below detection limit.

spent regenerating chemicals. The chemical characteristics of the wastewater produced depend upon the type of ion-exchange involved and the influent water quality. Typical wastewaters contain suspended solids, regenerants (typically sulfuric acid, sodium chloride or sodium hydroxide) and the cation/anion impurities, commonly calcium, magnesium, potassium, sodium, sulfate, chloride, nitrate, phosphate, bicarbonate, carbonate, hydroxide, and silica (in the form of $HSiO_3^-$) [16]. The volume of wastewater produced depends on the size and design of the ion-exchange unit. Typically, the bed is washed for 10 min to 15 min at a flow rate of 3.4×10^{-3} m^3/s to 4.1×10^{-3} m^3/s per square meter of bed area. The cation resins are then contacted for approximately 30 minutes by the regenerant which passes through the resin at a controlled rate. The cation regenerant consists of an acid or sodium ion solution at a concentration two to four times the stoichiometric exchange capacity of the resin. Approximately 8 m^3 of water per cubic meter of resin is used to rinse the bed after regeneration. Anion resins are contacted for about 90 minutes with sodium hydroxide at an approximate concentration of 4%. The rinse is about 10 m^3 of water per cubic meter of resin [16]. The frequency of regeneration depends on the influent characteristics and the bed volume.

Evaporation, used occasionally for boiler water treatment, purifies feedwater by vaporizing the water and then collecting and condensing the vapors. During the evaporation process, a blowdown stream is maintained to prevent dissolved solids from scaling the heat transfer surfaces. Blowdown compositions are similar to those of the influent water except impurity concentrations are several times larger. However, due to the decomposition of bicarbonate ions into carbon dioxide and carbonate ions, the pH rises to a pH between 6 and 9.

Filtration is used after several other water treatment operations. Because filters require periodic back washing,they too produce wastewater.

Reverse osmosis is a process used by some plants to remove dissolved salts. A concentrated salt solution is discharged as a waste.

Table 30 presents pollutant concentrations observed in the above water treatment wastewater streams.

Waste Streams from Boiler Blowdown

In addition to feedwater treatment, internal treatment of boiler waters is performed to prevent scale formation, to precipitate dissolved solids as a sludge, and to maintain the sludge in a fluid state for removal as blowdown. Blowdown, the controlled

TABLE 30. BOILER FEEDWATER TREATMENT - RAW WASTEWATER POLLUTION CONCENTRATIONS [16, 91]

Parameter	Clarification discharge	Softening[a] discharge			Ion exchange[b] discharge			
	Mean	Number of plants	Range	Median	Number of plants	Range	Median	Mean
Toxic pollutants, g/m³								
Chromium		3	0.09 - 0.11	0.1	5	0.02 - 0.2	0.07	
Copper		3	0.06 - 0.15	0.12	5	0.02 - 1.3	0.02	
Cyanide		3	0.005 - 0.014	0.005	3		0.005	
Nickel		3	0.07 - 0.25	0.09	5	0.03 - 0.2	0.03	
Zinc		3	0.09 - 0.32	0.12	4	0.02 - 0.21	0.05	
Classical parameters, g/m³								
Ammonia								46
BOD_5		3	1.8 - 48	10	3	1.0 - 6.0	1.0	
Bromide					3	0.03 - 1.5	1.0	
Chloride								1,700
COD		3	37 - 560	200	3	2.0 - 14	9.8	
Oil and grease		3	None	1.0	5	1.0 - 13	1.0	
Sulfate								2,100
TDS		3	190 - 23,000	1,000	3	0.16 - 4,000	170	
TSS	25,000	3	40 - 9,400	1,800	4	1.0 - 31	23	
Other pollutants, g/m³								
Iron	350	3	0.44 - 10	9.0	3	0.02 - 9.5	1.0	
Sodium								3,100

Parameter	Evaporation[c] discharge				Filtration discharge[d]				Other treatment-reverse osmosis discharge[d]			
	Number of plants	Range	Median	Mear.	Number of plants	Range	Median		Number of plants	Range	Median	
Toxic pollutants, g/m³												
Antimony					1		(<5)	<5	1		(<5)	<5
Arsenic					1		(13)	14	1		(<5)	<5
Beryllium					1		(<5)	<5	1		(<5)	<5
Cadmium					1		(<5)	<5	1		(<5)	<5
Chromium	2	0.2 - 0.08	0.05		1		(<5)	21	1		(<5)	<5
Copper	2	0.02 - 2.6	1.3		1		(<5)	40	1		(10)	30
Cyanide	2	0.006 - 0.028	0.017		1		(<20)	30	1		(20)	30
Lead					1		(<5)	20	1		(<5)	<5
Mercury					1		(0.39)	0.39	1		(0.53)	0.55
Nickel	2		0.03		1		(<5)	28	1		(<5)	<5
Selenium					1		(20)	12	1		(13)	58
Silver					1		(<5)	<5	1		(9)	<5
Thallium					1		(<5)	<5	1		(<5)	<5
Zinc	2	0.11 - 0.44	0.28		1		(<5)	41	1		(13)	14

(continued)

TABLE 30 (continued)

Parameter	Evaporation[c] discharge: Number of plants	Range	Median	Mean	Filtration discharge[d]: Number of plants	Range	Median	Other treatment-reverse osmosis discharge[d]: Number of plants	Range	Median
Phthalates, mg/m³										
Bis(2-ethylhexyl) phthalate					1		(1) <1	1		(1) <1
Phenols, mg/m³										
Phenol					1		(253) 13	1		(50) 1
Aromatics, mg/m³										
Benzene								1		(3) 2
Ethylbenzene								1		(<1) 3
Toluene					1		(<1) 150	1		(<1) 46
Halogenated aliphatics, mg/m³										
Chloroform					1		(3) 5.2	1		(<1) 23
Methylene chloride					1		(3) 1.4	1		(1) <1
Classical parameters, g/m³										
BOD_5	2	5.1 - 15	10							
Chloride				190						
COD	2	21 - 76	48							
Oil and grease	2	1.0 - 1.9	1.5							
Phenols					1		(50) 20	1		(10) 20
Sulfate				79						
TDS	2	2,200 - 2,500	2,400							
TSS	2	15 - 93	54							
Other pollutants, g/m³										
Iron	2	0.22 - 0.38	0.30							

[a] Lime softener blowdown.

[b] Demineralizer regeneration.

[c] Evaporator blowdown.

[d] Intake concentrations in parentheses.

Note: Blanks indicate data not available.

discharge of a portion of the boiler water, can be either continuous or intermittent. The quantity of blowdown wastewater varies up to 0.02 m^3 per 450 kg of steam generated [16].

Boiler blowdown characteristics vary with the quality of the feedwater and the chemicals used for internal treatment. Some of the chemicals used for scale prevention, corrosion inhibition, pH control, and oxygen scavenging are included in Table 27 (shown earlier). Generally, blowdown is an alkaline waste with a pH value of 9.5 to 11.

Blowdown from medium-pressure boilers has a total dissolved solids (TDS) concentration in the range of 100 g/m^3 to 500 g/m^3 while that from high-pressure boilers is in the range of 10 g/m^3 to 100 g/m^3. If phosphate treatment is used for scale or corrosion control, the waste will contain from 5 g/m^3 to 50 g/m^3 of phosphate and from 10 g/m^3 to 100 g/m^3 of hydroxide alkalinity. Blowdown from boilers in which hydrazine is used for oxygen scavenging contains up to 2 g/m^3 of ammonia [16]. Boiler blowdown is generally of fairly high quality because the boiler feedwater must be maintained at high quality. Table 31 presents raw waste concentrations for boiler blowdown wastewater streams [91].

TABLE 31. BOILER OR STEAM GENERATOR BLOWDOWN - RAW WASTEWATER POLLUTION CONCENTRATIONS [91]

	Boiler blowdown discharge		
		Concentration, g/m^3	
Parameter	Number of plants	Range	Median
Toxic pollutants			
Chromium	4		0.02
Copper	4	0.02 - 0.19	0.04
Cyanide	2	0.005 - 0.014	0.010
Nickel	4		0.03
Zinc	4	0.01 - 0.05	0.02
Classical parameters			
BOD_5	2	11 - 12	11
COD	2	2.0 - 157	80
Iron	4	0.03 - 1.4	0.06
Oil and grease	2	1.0 - 15	7.9
pH	4	9.0 - 12	10
TDS	2	120 - 1,410	760
TSS	4	2.7 - 31	7.6

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[91] Supplement for Pretreatment to the Development Document for the Steam Electric Power Generating Point Source Category. EPA-440/1-77-084, U.S. Environmental Protection Agency, Washington, D.C., April 1977. 244 pp.

3089 AmL

Waste Streams from Equipment Cleaning

Periodically, boiler equipment must be removed from service and cleaned to maintain the heat transfer surfaces and other miscellaneous parts. Because each cleaning operation is tailored to the needs of particular equipment, the major operations involved are briefly reviewed on an individual basis in the following paragraphs.

Water Side Boiler Cleaning--

Because of differences in boiler scale composition, no set process exists for the internal cleaning of boiler tubes. Normally, the cleaning chemicals and procedure are based on the analysis of a boiler-scale sample. The nature of the resultant wastewater depends on the cleaning agents used, but it may contain alkalinity, organic compounds, phosphates, ammonium compounds, and scale components such as copper, iron and hardness. The frequency of boiler-tube cleaning varies considerably. In one study, the average time between cleanings was thirty months with a standard deviation of eighteen months, and its range was one cleaning every seven months to one cleaning every 100 months [16].

Boiler Fireside Cleaning--

Boiler tube exteriors are cleaned to remove ash and corrosion products. Cleaning may be accomplished using a high-pressure hose or chemicals such as soda ash or other alkaline materials to enhance the cleaning action. The waste stream may show high values for pH and hardness, and will contain suspended solids and some metals.

Condensor Cleaning--

Although the steam side of a condenser rarely requires cleaning, the water side is usually cleaned with HCl. Inhibitors are added to reduce corrosion of metal surfaces during cleaning.

Air Preheater Cleaning--

Preheaters are generally cleaned in a manner similar to that used in boiler firesides. Soda ash and phosphates or detergents may be added to the high-pressure water stream. Depending on the sulfur content of the fuel, effluents are more or less acidic in nature. Waste stream constituents include fly ash, soot, rust, magnesium salts, and metallic ions (copper, iron, nickel, and chromium are usually prevalent). Preheater cleaning is performed about once each month, although this varies from four to 180 times per year between plants.

Other Equipment Cleaning--

Miscellaneous equipment also requires cleaning; this includes feedwater heaters, stacks, cooling-tower basins, air-compressor coolers, and other units. The cleaning processes, chemicals, and waste-stream characteristics are similar to those described above.

Pollutant concentrations in wastewaters from boiler tube cleanings are given in Table 32 along with the composition of the respective cleaning solutions [90]. Similar data for boiler fireside and air preheater cleanings appears in Table 33 [90].

Waste Streams from Ash Handling and Ash Pond Wastewaters

Bottom ash and fly ash may be handled and transported on site using wet (sluicing) or dry (pneumatic) methods depending on the ash volume, type of collection system (i.e., wet scrubbers or ESP), availability of land, cost of water, and other factors. While no data is available on the percent usage of the wet or dry methods for the specific source type being studied, one report assumes that boilers with design capacities less than 530 GJ/hr handle their ash using a dry method [2].

Handling and transport water usage ranges from 5 m^3/metric ton to 17 m^3/metric ton of ash conveyed for fly ash, and from 10 m^3/metric ton to 170 m^3/metric ton of ash conveyed for bottom ash. Ash pond discharge rates for the utility sector vary from approximately 0.005 m^3/s to approximately 0.8 m^3/s per million metric tons of coal burned per year, with the median value being approximately 0.2 m^3/s per million metric tons of coal burned per year [16]. Pollutants in the discharge consist of coal ash and its soluble components. Table 34 shows effluent pollutant concentrations from ash handling systems [90].

To supplement the data in Table 34, MRC analyzed ash slurry samples obtained from a large coal-fired power plant. A special effort was made to detect POM's and PCB's. A detailed description of the analytical procedure and results is given in Appendix D. No PCB's were found in any of the samples. POM concentrations were generally below 1 mg/m^3 corresponding to very low effluent severities as shown later in Table 52.

Waste Streams from Wet Scrubber Effluents

Wet scrubbers for air pollution control use a water solution to absorb and remove sulfur oxide and fly ash from flue gas. Sulfur oxide scrubbers generally use an aqueous slurry of lime or limestone which reacts with SO_x to form calcium sulfite and calcium sulfate, both of which precipitate. The effluent stream is usually recycled to the scrubber after removal of the precipitate as a sludge. Tables 35 and 36 give effluent data for raw and treated wastewaters, respectively, from flue gas desulfurization (FGD) scrubber systems [90].

TABLE 32. MAINTENANCE CLEANING-BOILER OR GENERATOR TUBE WASH SOLUTIONS-RAW WASTEWATER POLLUTANT CONCENTRATION [90]

	Ammoniated citric acid discharge			Ammoniated EDTA discharge			Ammoniacal sodium bromate discharge		
Parameter	Number of operations[a]	Range	Median	Number of operations	Range	Median	Number of operations	Range	Median
Toxic pollutants, g/m^3									
Arsenic							3	<0.005 - 310	0.48
Beryllium							2		<0.01
Cadmium							3	<0.001 - <0.02	<0.001
Chromium				3	10 - 27	12	4	ND - <0.05	<0.005
Copper	3	8 - 220	20	7	0.17 - 12,000	120	6	100 - 790	370
Lead									
Mercury							3	<0.00002 - 15	<0.00002
Nickel	1		120	3	12 - 140	68	5	ND - 260	0.52
Selenium							3	<0.002 - 24	<0.002
Silver							2	<0.01 - 0.02	0.02
Zinc	1		390	3	79 - 140	120	5	0.05 - 1.0	0.5
Classical parameters[b]									
pH[c]				7	8.8 - 10	9.2	2	10 - 11	10
TDS				2	60,000 - 74,000	67,000	3	340 - 1,400	1,000
TSS				1		24	3	8 - 77	71
COD							2	24 - 120	72
Oil and grease				1		41	2		<5
NH_3-N				1		5,200	2	700 - 2,000	1,400
Org-N							2	<10 - 40	25
NO_2+NO_3-N							2	0.04 - 0.51	0.27
Silica	1		40	1		94	2	7.2 - 14	11
Bromide							2	<5 - 52	28
Chloride							1		60
Other pollutants, g/m^3									
Aluminum				1		31	2		<0.2
Barium							2		<0.1
Calcium				2	21 - 45	33	3	ND - 3.0	0.4
Iron	3	8,300 - 11,000	9,800	7	2,300 - 8,300	6,900	5	ND - 4.9	1.7
Manganese				2	50 - 73	61	3	0.01 - 0.04	0.03
Magnesium				2	11 - 21	16	3	ND - 2.9	0.67
Phosphorus	1		200	1		260	2	10 - 30	20
Potassium							2	70 - 220	150
Sodium				1		370	3	3.7 - 59	15
Tin							2		<1

(continued)

TABLE 32 (continued)

Parameter	Hydrochloric acid without copper complexer discharge			Hydrochloric acid with copper complexer discharge			Hydroxyacetic/formic acid discharge		
	Number of operations	Range	Median	Number of operations	Range	Median	Number of operations	Range	Median
Toxic pollutants, g/m^3									
Arsenic	6	0.008 - 0.06	0.033						
Beryllium	4		<0.01						
Cadmium	6	<0.001 - 0.051	0.06						
Chromium	6	<0.005 - 8.8	3.8	1		17			
Copper	6	0.69 - 47	10	6	20 - 960	370	1		2
Lead	5	<0.01 - 5.2	0.86						
Mercury	4		<0.002						
Nickel	7	77 - 300	160	5	3 - 500	270	1		[illegible]
Selenium	4	<0.002 - <0.004	<0.002						
Silver	4	0.02 - 0.07	0.03						
Zinc	7	0.94 - 170	20	4	10 - 840	410	1		8
Classical parameters^b									
pH^c	6	0.5 - 3.3	0.7						
TDS						31,000			
TSS	6	8 - 120	34	1		2,400			
COD	6	1,200 - 9,900	1,500						
TOC	6	90 - 4,600	230						
Oil and grease	6	<5 - 23	16						
Phenols	6	0.020 - 0.070	0.043						
NH_3-N	6	80 - 330	190						
Org-N	6	0.06 - 870	108						
NO_2+NO_3-N	4	<0.01 - 0.07	<0.01						
Silica	5	19 - 240	66	2	30 - 280	160			
Sulfate	4	<1 - 10	<1						
Other pollutants, g/m^3									
Aluminum	4	6.5 - 8.2	6.8						
Barium	4	<0.1 - 0.4	0.2						
Calcium	6	16 - 74	59	2	67 - 980	520			
Iron	7	1,100 - 4,200	2,800	6	1,900 - 6,500	3,900	4	2,900 - 9,800	4,600
Manganese	6	6.9 - 29	21	1		8.2			
Magnesium	4	5.7 - 8.8	7.6						
Phosphorus	6	1.2 - 50	40	2	100 - 300	200			
Potassium	4	1.4 - 2.3	1.7						
Sodium	4	31 - 74	45	1		9.2			
Tin	4	<1 - 7.3	1.9						

[a] Number of independent boiler chemical cleaning operations.

[b] Values in g/m^3 except as noted.

[c] Values in pH units.

Note: Blanks indicate data not available.
ND = not detected.

TABLE 33. MAINTENANCE CLEANING - BOILER FIRESIDE AND AIR PREHEATER [90]

Parameter	Boiler fireside wash[a]				Air preheater wash water[a]			Air preheater and fireside wash[b]	
	Concentration, g/M³		Mean loading, kg/cleaning (lb/cleaning)		Number of operations	Concentration, g/M³		concentration, g/m³	
	Maximum	Mean	kg/cleaning	(lb/cleaning)		Range	Median	Intake	Discharge
Toxic pollutants									
Beryllium								6	
Cadmium							6	20	
Chromium (total)	15	1.5	6.8	(15)	3	1.0 - 1.5	1.3	10	200
Chromium +6	<1.0	0.02	0.09	(0.2)					
Copper	250	6.0	27	(60)				7	200
Lead								30	600
Nickel	900	70	317	(700)	3	18 - 25	21	BDL	100
Zinc	40	4.0	18	(40)	3	1.1 - 1.5	1.2	BDL	900
Classical parameters									
pH[c]					3	3.2 - 3.5[c]	3.5[c]		
TDS	50,000	5,000	23,000	(50,000)	3	606 - 750	730		
TSS	25,000	250	1,100	(2,500)	3	29 - 83	34		
COD					3	50 - 70	60		
Chloride					3	17 - 27	19		
Sulfate	10,000	1,000	4,500	(10,000)	3	1,900 - 2,700	2,300		
Oil and grease	BDL	BDL	BDL		3	0.25 - 8.5	0.25		
Total hardness, as $CaCO_3$					3	1,400 - 1,600	1,500		
Other pollutants									
Aluminum	21	2.0	9	(20)					
Calcium					3	29 - 38	34		
Iron	14,000	2,500	11,000	(25,000)	3	340 - 520	460		
Magnesium					3	260 - 370	330		
Manganese	40	3.5	16	(35)					
Sodium					3	360 - 380	370		

[a] Data from one plant.

[b] Verification date.

[c] Values in pH units.

Note: Blanks indicate data not available.

TABLE 34. ASH HANDLING - INTAKE, INFLUENT, AND EFFLUENT POLLUTANT CONCENTRATIONS [90]

Pollutant	Bottom ash[a,b]								
	Influent			Effluent			Intake		
	Number of plants	Range	Median	Number of plants	Range	Median	Number of plants	Range	Median
Toxic pollutants, mg/m^3									
Antimony				3	5 - 7	6	3	3 - 7	4
Arsenic				3	BDL - 74	9	2	BDL - 3	
Beryllium	6	2 - 10	6	5	BDL - 2.5	<1.0	2	BDL - <1	
Cadmium	6	8 - 100	45	5	BDL - 10	2	4	BDL - 40	2
Chromium	6	60 - 900	200	8	BDL - 1,000	9	6	BDL - 2,000	9
Copper	6	50 - 200	100	8	13 - 80	26	7	<6 - 700	16
Cyanide				8	BDL - 22	<20	2	4 - 5	5
Lead	6	50 - 1,000	200	8	BDL - 30	13	4	9 - 20	13
Mercury				6	BDL - 1.5	<0.5	1		<0.5
Nickel	6	20 - 500	95	8	2.5 - 490	14	8	BDL - 1,000	9
Selenium				3	3 - 42	8	3	BDL - 2	2
Silver	3	2 - 20	8	4	0.5 - 6	3.3	4	BDL - 1.6	1.2
Thallium				3	BDL - 9	BDL	1		BDL
Zinc	6	100 - 900	500	8	BDL - 300	<60	6	15 - 70	57
Pnthalates, mg/m^3									
Bis(2-ethylhexyl) phthalate				6	21 - 309	22	2	<10 - 21	16
Butyl benzyl phthalate				1		10	1		<10
Di-n-butyl phthalate	1		65	3	31 - 46	36	4	<10 - 33	<10
Diethyl phthalate							1		<10
Di-n-octyl phthalate							1		<10
Phenols, mg/m^3									
2,4-Dichlorophenol				1		83	3		<25
2,4-Dinitrophenol				1		50	3		<25
Pentachlorophenol				1		51			
Phenol				5	6 - 40	14	5	6 - 36	12
2,4,6-Trichlorophenol							2	<25 - 28	27
Aromatics, mg/m^3									
1,2-Dichlorobenzene				2	64 - 65	65	3		<10
1,3-Dichlorobenzene	1		35	2	64 - 65	65	3		<10
1,4-Dichlorobenzene				2	64 - 65	65	3		<10
1,2,4-Trichlorobenzene							1		<10
Polycyclic aromatic hydrocarbons, mg/m^3									
Acenaphthylene	1		16				1		<10
2-Chloronaphthalene				1		52			
Halogenated aliphatics, mg/m^3									
1,2-Dichloroethane				1		27			
Methylene chloride			5,400	6	300 - 9,400	>1,800	1		48

(continued)

TABLE 34 (continued)

	Fly Ash[a]								
	Influent			Effluent			Intake		
Pollutant	Number of plants	Range	Median	Number of plants	Range	Median	Number of plants	Range	Median
Toxic pollutants, mg/M^3									
Beryllium	2	30 - 400	215						
Cadmium	2	80 - 200	140	1		90	1		<2
Chromium	2	400 - 2,000	1,200	2	9 - 49	29	2	12 - 2,000	1,000
Copper	2	400 - 2,000	1,200	2	12 - 19	16	2	13 - 90	52
Lead	2		4,000	2	23 - 70	47	1		15
Mercury				2		<0.5			
Nickel	2	400 - 2,000	1,200	2	32 - 75	54	2	<5 - 1,000	570
Silver	2	10 - 100	55						
Zinc	2	8,000 - 10,000	9,000	2	60 - 1,200	630	2		<60
Phthalates, mg/m^3									
Bis(2-ethylhexyl) phthalate				2	17 - 25	21			
Di-n-butyl phthalate			46	2	7 - 48	28	2	<10 - 42	26
Phenols, mg/m^3									
Phenol				1		35	1		38
Aromatics, mg/m^3									
1,2-Dichlorobenzene				1		41	1		<10
1,3-Dichlorobenzene				1		41	1		<10
1,4-Dichlorobenzene				1		41	1		<10
Halogenated aliphatics, mg/m^3									
Methylene chloride				2	<140 - <9,400	<4,800			

[a] Verification data.

[b] Coal-fueled plants only.

Note: Blanks indicate data not available.

TABLE 35. AIR POLLUTION CONTROL DEVICES - NONREGENERABLE FLUE GAS DESULFURIZATION (FGD) PROCESSES - RAW WASTEWATER POLLUTANT CONCENTRATIONS [90]

Parameter	Most eliminator wash water (wet limestone) discharge concentration, g/m³			Bleed stream (wet lime/limestone)[b] discharge concentration range, g/m³	Sludges - lime limestone and double-alkali system[c] discharge	
	Flowrate, L/min/m³				Concentration range, g/m³	Loading range, mg/kg[a]
	40.7	20.35	10.18			
Toxic pollutants						
Antimony				0.09 - 2.3		
Arsenic	0.002	0.002	0.01	<0.004 - 0.3	0.004 - 1.8	0.6 - 52
Beryllium	0.1	<0.01	<0.01	<0.002 - 0.14	0.002 - 0.18	0.05 - 6
Cadmium	0.0042	0.0013	0.0031	0.004 - 0.11	0.004 - 0.11	0.08 - 4
Chromium	<0.05	<0.05	<0.05	0.01 - 0.5	0.015 - 0.5	10 - 250
Copper	0.02	0.02	0.03	<0.002 - 0.2	0.002 - 0.56	8 - 76
Cyanide	<0.01	<0.01	<0.01			
Lead	0.033	0.011	0.016	0.01 - 0.4	0.01 - 0.52	0.23 - 21
Mercury	<0.0002	<0.0002	<0.0002	0.0004 - 0.07	0.0004 - 0.07	0.001 - 5
Nickel	<0.05	<0.05	<0.05	0.05 - 1.5		
Selenium	0.012	0.024		<0.001 - 2.2	0.0006 - 2.7	2 - 17
Silver	<0.01	<0.01	<0.01	0.005 - 0.6		
Zinc	0.07	0.02	0.14	0.01 - 0.35	0.01 - 0.59	45 - 430
Classical parameters						
ph	3.1[d]		2.7[d]	3.04 - 11[d]	4.3 - 12.7[d]	
TDS	1,000	1,900	2,200	3,200 - 15,000	2,800 - 92,000	
COD				60 - 390	1 - 390	
Alkalinity, as $CaCO_3$	580	1,100	1,100	41 - 150		
Acidity, as $CaCO_3$	64		150			
Conductance[e]	1.300[e]	1,600[e]	2,700[e]	3 - 15[e]		
Turbidity[f]	<1[f]	<1[f]	2[f]	<3 - <10[f]		
Silica				0.2 - 3.3		
Fluoride				0.07 - 10	0.6 - 38	
Chloride	24	40	120	420 - 4,800	420 - 33,000	0 - 9,000
Sulfate	700	1,000	1,200	720 - 10,000	600 - 35,000	35,000 - 470,000
Sulfite				0.8 - 3,500	0.9 - 3,500	1,600 - 300,000
Ammonia	0.21	0.25	0.34			
Phosphate	0.11	0.03	0.03	0.03 - 0.41		
Other pollutants						
Aluminum	<0.2	<0.2	<0.2	0.03 - 0.3	0.03 - 2.0	
Barium	<0.1	<0.1	<0.1			
Boron				8 - 46		
Calcium	220	440	430	520 - 3,000	180 - 2,600	[illegible],000 - 270,000
Cobalt				0.1 - 0.7		
Iron	5.8	0.07	5.5	0.2 - 8.1		
Manganese	0.16	0.14	0.37	0.09 - 2.5		
Magnesium	6.5	8.2	18	3 - 2,700	4.0 - 2,800	
Molybdenum				0.91 - 6.3		
Potassium	2.2	3	2.6	5.9 - 32	5.9 - 100	
Sodium	8.1	8.8	11	14 - 2,400	10.0 - 29,000	0 - 48,000
Tin				3.1 - 3.5		
Vanadium				0.001 - 0.67		

[a] Values in other units are footnoted.

[b] Data from three plants.

[c] Data from seven plants burning coal and using lime, limestone, or double-alkali absorbents.

[d] Values in pH units.

[e] Values in µmhos/cm.

[f] Values in JTU.

Note: Blanks indicate data not available.

TABLE 36. POLLUTION CONTROL DEVICES - NONREGENERABLE FGD PROCESSES - SETTLING POND INFLUENT AND TREATED EFFLUENT MEDIAN CONCENTRATIONS [90]

Parameter	Pond A		Pond B		Pond C		Pond D	
	Input liquor	Supernate	Input liquor	Supernate	Input liquor	Supernate	Input liquor	Supernate
Toxic pollutants, g/m³								
Arsenic	0.024	0.005		0.005		0.006	0.24	0.07
Lead	0.010	0.016		0.020		0.026	0.26	0.010
Mercury	0.0005	0.0002		0.001		0.0002	0.0001	0.0002
Selenium	0.002	0.002		0.021		0.003		
Classical parameters[b]								
pH[c]	8.2	8.0	7.1	9.6	8.1	11	8.2	8.4
TDS	7,110	2,800	6,100	2,200	9,000	1,600	5,900	3,400
TSS	16	9		8		9		98
COD	20	37		43		19		19
Alkalinity, as CaCO₃	81	49		190		100		97
Conductivity[d]	10.0	3.2	5.4	8.3	8.2	2.4	5.2	3.9
Chloride	3,604	630	2,400	1,500	4,200	500	1,800	980
Sulfate	1,400	1,100	1,700	900	1,600	200	2,300	1,000
Sulfite	32	0.8	120	70	80	0.85		
Other pollutants, g/m³								
Boron	16	5.5		60		0.30	90	43
Calcium	2,000	880	1,400	1,700	2,600	470	1,300	910
Magnesium	210		390	0.9	240	1.7	260	96
Sodium	68	20	38	34	60			

[a] Analyses of input liquors to four disposal ponds and subsequent supernates at one plant. All four disposal ponds were filled with effluents representing a cross section of lime or limestone scrubber effluent conditions.

[b] Values in g/m³ except as noted.

[c] Values in pH units.

[d] Values in μmhos/cm.

Waste Streams from Rainfall Runoff

Runoff from coal-storage piles contains mineral acids, dissolved solids, iron, sulfate, aluminum, copper, zinc, and manganese. Though potentially hazardous, no further assessment of rainfall runoff is included in this report because that source has been assessed [92].

Other Waste Streams

At a given electric generating site, a number of minor waste streams may be present; these include sanitary wastes, floor drains, and laboratory drains. Because such sources are of low volume and usually feed into a public sewer system, they are not covered in this assessment report. Information on these streams can be found in the literature [90, 93].

EFFLUENT DATA

In order to put the pollutant concentrations given in the previous sections on a more usable basis, they were converted to effluent factors. Effluent factors were obtained for each waste stream by employing the following equation:

$$EF = \frac{C_D V_D}{R}$$

where EF = effluent factor, grams of pollutant/kg coal

C_D = net pollutant discharge concentrations, grams pollutant/m^3

V_D = median effluent stream discharge rate, m^3/d

R = average coal consumption rate, kg coal/d

Because effluent concentrations are dependent upon the pollutant quantities in the intake stream, the concentration term in the above equation is expressed as the difference between the intake and effluent pollutant concentrations. The result is the amount of pollutant actually added to the stream. The intake water for the water treatment, boiler blowdown, and maintenance cleaning processes was assumed to be tap water. Literature was used to develop an average tap water composition as shown in Table 37 [2, 94, 95].

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[92] Wachter, R. A., and T. R. Blackwood. Source Assessment: Water Pollutants from Coal Storage Areas. EPA-600/2-78-004m (PB 285 420), U.S. Environmental Protection Agency, Cincinnati, Ohio, May 1978. 121 pp.

[93] Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source Category. EPA-440/1-74-029a, U.S. Environmental Protection Agency, Washington, D.C., October 1974. 842 pp.

Because of varying compositions among rivers, such a table was not established for river water used in cooling. Rather, only effluent data containing both inlet and outlet compositions was considered. When intake concentrations were unknown or below detection limits, they were assumed to be zero. This assumption may give a higher than normal net concentration (C_D), thus providing a "worst case" effluent factor. Note that although this assumption is good for tap water, significant error may exist in effluent factors developed using this assumption for streams with river water sources.

Wastewater discharge rates are reported in Table 38; they were obtained from References 90 and 91, except for the once through cooling flow rate which was determined from data in References 16, 91, and 96. The ash handling wastewater flow given in Table 38 is for a combined (fly ash and bottom ash) waste stream. Since approximately 80 percent of the ash released in combustion at a coal-fired utility boiler is fly ash, this factor was applied to obtain the flow required for fly ash removal. A similar procedure was used for the bottom ash flow rate.

The average coal consumption rate for this source type, as given in Section 3 of this report, is 11 kg/s. Resulting effluent factors for each wastewater stream appear in Tables 39-45.

POTENTIAL ENVIRONMENTAL EFFECTS

Industrial wastes discharged to a river or lake can have a detrimental effect on aquatic life and on other animals, including man, that use the water for recreational purposes (fishing,

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[94] Draft Engineering Report for Development of Effluent Limitations Guidelines for the Paint Manufacturing Industry. U.S. Environmental Protection Agency, Effluent Guidelines Division, Washington, D.C., January 1979.

[95] Draft Engineering Report for Development of Effluent Limitations Guidelines for the Ink Manufacturing Industry. U.S. Environmental Protection Agency, Effluent Guidelines Division, Washington, D.C., January 1979.

[96] Steam-Electric Plant Air and Water Quality Control Data; Summary Report. FPC-S-253, Federal Power Commission, Washington, D.C., January 1976. 224 pp.

TABLE 37. TYPICAL TAP WATER COMPOSITION [2, 94, 95]

Parameter	Concentration, g/m³		Parameter	Concentration, g/m³	
	Range	Median		Range	Median
Toxic pollutants			Classical parameters		
Antimony	<0.01 - <0.1	<0.01	pH (units)	6 - 8.8	7.5
Arsenic		<0.002[a]	TDS	56 - 2,299	380
Beryllium	<0.001 - 0.02	<0.005[a]	TSS	1 - 9	3
Cadmium	<0.002 - <0.2	0.0039	BOD_5	<2.4 - 6	<2.4
Chromium	<0.005 - <0.2	0.0140	COD	1.5 - 24	6.4
Copper	<0.006 - <0.6	0.0106	TOC	<1 - 16	8
Cyanide	<0.02 - 0.09	<0.02	Oil and grease	<1 - 2	<1
Lead	<0.02 - 0.4	0.0612	Phenols	<0.005 - 0.03	0.012
Mercury	<0.0005 - 6	<0.0005	NH_3		<0.05[a]
Nickel	<0.005 - 0.2	<0.05			
Selenium	None	<0.01[a]			
Silver	<0.001 - 0.04	<0.01	Other pollutants		
Thallium	None	<0.01	Aluminum	<0.05 - 20	<0.5
Zinc	Up to 5	0.0369	Barium	<0.005 - 0.6	0.040
Benzene	<0.01[a] - 0.135	<0.01[a]	Calcium	<1 - 420	23.9
Chloroform	<0.01[a] - 0.570	<0.01[a]	Iron	<0.2 - 3	<2
Di-2-ethylhexyl-			Magnesium	<5 - 70	<11
phthalate	<0.01[a] - 0.164	<0.01[a]	Manganese	Up to 0.07	0.0007
Ethylbenzene	<0.01[a] - 0.420	<0.04	Phosphorus		0.205
Methylene chloride	<0.01[a] - 0.164	<0.01[a]	Sodium	Up to 240	23.2
Phenol	None	<0.01[a]	Tin	0.03 - 0.3	<0.05
Toluene	<0.01[a] - 2.70	<0.01[a]			

[a] Below detection limit, detection limit is given.

TABLE 38. WASTEWATER FLOWRATES [90,91]

Waste stream	Type fuel	Number of plants	Flowrate, m^3/d (gpd) Range		Median		Frequency	Remarks
1. Condenser cooling water								
Once-through[a]	All	-	1.68×10^5 - 1.44×10^6	(4.47×10^7 - 3.83×10^8)	7.36×10^5	(1.96×10^8)	-	
Recirculating	All	5	53 - 1,000	(14,000 - 280,000)	240	(63,000)		Blowdown depends on water quality and varies from 2 to 20 concentrations
2. Water treatment								
Clarification	Coal	88	0.026 - 2,300	(7 - 60,000)	102	(27,000)		
Softening	Coal	37	0.11 - 190	(29 - 50,000)	99	(26,000)		
Ion exchange	Coal	104	0.055 - 400	(14 - 100,000)	35	(9,300)	52-365 cycles/yr	Extremely variable depending upon raw water quality
Evaporation	Coal	104	0.0076 - 3,600	(2 - 960,000)	110	(29,000)	300-365 cycles/yr	Extremely variable depending upon raw water quality
Filtration	Coal	155	0.0061 - 1,100	(1.6 - 300,000)	97	(25,000)		
Reverse osmosis	Coal	3	0.011 - 120	(3 - 32,000)	40	(11,000)	-	
3. Boiler blowdown	Coal	231	0.00042 - 2,500	(0.11 - 650,000)	130	(33,000)	25-365 cycles/yr	
4. Maintenance (chemical) cleaning								
Boiler tubes	All	7	570 - 19,000	(150,000 - 4,900,000)	870	(230,000)	Once/7-100 mo	
Boiler fireside	Coal	42	0.010 - 77	(2.7 - 20,000)	10	(2,700)	2-8 yr	
Air preheater	Coal	148	0.010 - 590	(2.7 - 160,000)	41	(11,000)	4-12 yr	
5. Ash handling	Coal	24	1,800 - 78,000	(480,000 - 21,000,000)	18,000	(4,700,000)		
6. Air pollution control devices								
Scrubber blowdown	Coal	13	27 - 57,000	(7,000 - 15,000,000)	6,500	(1,700,000)	-	
Scrubber solids pond overflow	Coal	7	0.95 - 8,700	(250 - 2,300,000)	3,200	(840,000)	-	

[a] Data from References 91, 93, and 96.

TABLE 39. EFFLUENT FACTORS FOR CONDENSER COOLING SYSTEM

Pollutant	Effluent factors, g/kg coal Once through cooling water systems	 Recirculating cooling water systems
Toxic pollutants		
Antimony	0^{a}	$-^{b}$
Arsenic		1.6×10^{-6}
Beryllium	0^{a}	
Cadmium	0^{a}	$-^{b}$
Chromium	$-^{b}$	$-^{b}$
Copper	3.2×10^{-3}	6.3×10^{-6}
Cyanide		5.2×10^{-6}
Lead	$-^{b}$	$-^{b}$
Mercury	8.8×10^{-5}	
Nickel	1.4×10^{-2}	3.4×10^{-6}
Selenium		
Silver	$-^{b}$	4.5×10^{-7}
Thallium	0^{a}	$-^{c}$
Zinc	0^{a}	4.9×10^{-8}
Phenol (total)	1.6×10^{-2}	
Phthalates		
Bis(2-ethylhexyl) phthalate	1.7×10^{-2}	2.6×10^{-7}
Butyl benzyl phthalate	$8.0 \times 10^{-3\,d}$	
Di-n-butyl phthalate	2.4×10^{-3}	$-^{b}$
Diethyl phthalate	$8.8 \times 10^{-3\,d}$	
Di-n-octyl phthalate	$8.0 \times 10^{-3\,d}$	
Phenols		
Phenol	$-^{b}$	$-^{b}$
2,4,6-Trichlorophenol	$-^{b}$	2.6×10^{-6}
Aromatics		
Benzene		1.2×10^{-5}
1,2-Dichlorobenzene	1.6×10^{-3}	2.6×10^{-6}
1,3-Dichlorobenzene	1.6×10^{-3}	2.6×10^{-6}
1,4-Dichlorobenzene	1.6×10^{-3}	2.6×10^{-6}
1,2,4-Trichlorobenzene		
Polycyclic aromatic hydrocarbons		
2-Chloronapthalene	$8.0 \times 10^{-3\,d}$	
Halogenated aliphatics		
Bromoform	2.7×10^{-1}	$2.1 \times 10^{-5\,d}$
Chlorodibromomethane		$1.5 \times 10^{-5\,d}$
1,2-Dichloroethane	$-^{b}$	
1,1-Dichloroethylene	$1.3 \times 10^{-2\,d}$	
1,2-*trans*-dichloroethylene	$8.8 \times 10^{-3\,d}$	
Methylene chloride	2.2	4.0×10^{-4}
Tetrachloroethylene	$6.3 \times 10^{-2\,d}$	
1,1,1-Trichloroethane	$9.6 \times 10^{-3\,d}$	$4.7 \times 10^{-6\,d}$

Note: Blanks indicate data not available.

[a] Inlet and discharge concentrations are equal.

[b] Median inlet concentrations are greater than median outlet concentrations.

[c] Both intake and outlet concentrations are below detectable limits.

[d] Inlet concentration was taken to be zero to provide a "worst case" analysis.

TABLE 40. EFFLUENT FACTORS FOR BOILER FEEDWATER TREATMENT

	Effluent factors (g/kg coal)					
Parameter	Clarification discharge	Softening discharge	Ion-exchange discharge	Evaporation discharge	Filtration[a] discharge	Other discharge
Toxic pollutants						
Chromium		9.3×10^{-6}	2.1×10^{-6}	4.3×10^{-6}	1.7×10^{-3}	
Copper		1.2×10^{-5}	3.6×10^{-7}	1.5×10^{-4}	3.7×10^{-3}	8.7×10^{-4}
Cyanide		-[b]	-[b]	-[b]	1.1×10^{-3}	4.4×10^{-4}
Nickel		4.5×10^{-6}	-[b]	-[b]	2.4×10^{-3}	
Zinc		9.0×10^{-6}	5.0×10^{-7}	2.9×10^{-5}	3.8×10^{-3}	4.4×10^{-5}
Benzene						-[b]
Chloroform					2.3×10^{-4}	9.6×10^{-4}
Ethyl benzene						8.7×10^{-5}
Methylene chloride					-[b]	-[b]
Phenol					-[b]	-[b]
Bis(2-ethylhexyl) phthalate					-[b]	-[b]
Toluene					1.6×10^{-2}	2.0×10^{-3}
Classical parameters						
TDS		6.7×10^{-2}	-[b]	2.5×10^{-1}		
TSS	2.8	1.9×10^{-1}	7.6×10^{-4}	6.1×10^{-3}		
BOD_5		8.2×10^{-4}	-[b]	9.1×10^{-4}		
COD		2.1×10^{-2}	1.3×10^{-4}	5.0×10^{-3}		
Oil and grease		-[b]	-[b]	6.0×10^{-5}		
Phenols					-[b]	
Ammonia			1.8×10^{-3}			
Bromide			3.8×10^{-5}[c]			
Chloride			6.5×10^{-2}[c]	2.3×10^{-2}[c]		
Sulfate			8.0×10^{-2}[c]	9.4×10^{-3}[c]		
Other pollutants						
Iron	3.9×10^{-2}	7.6×10^{-4}	-[b]	-[b]		
Sodium			1.2×10^{-1}			

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[a] Data based on only one plant.

[b] Median discharge concentration is less than the median intake concentration.

[c] Value is based on a zero inlet concentration to provide a "worst case" analysis.

TABLE 41. EFFLUENT FACTORS FOR BOILER BLOWDOWN

Parameter	Effluent factor, g/kg coal
Toxic pollutants	
Chromium	8.5×10^{-7}
Copper	4.2×10^{-6}
Cyanide	-[a]
Nickel	-[a]
Zinc	-[a]
Classical parameters	
BOD_5	1.2×10^{-3}
COD	1.0×10^{-2}
Iron	-[a]
Oil and grease	9.8×10^{-4}
TDS	5.4×10^{-2}
TSS	6.5×10^{-4}

[a] Intake concentrations exceed discharge concentrations.

TABLE 42. EFFLUENT FACTORS FOR MAINTENANCE CLEANING AND BOILER TUBE WASHING

Parameter	Ammoniated citric acid discharge effluent factor g/kg coal	Ammoniated EDTA discharge effluent factor, g/kg coal	Ammoniacal sodium bromate discharge effluent factor, g/kg coal	HCl without Cu complexer discharge effluent factor, g/kg coal	HCl with Cu complexer discharge effluent factor, g/kg coal	Hydroxyacetic/formic acid discharge effluent factor, g/kg coal
Toxic pollutants						
Arsenic			4.6×10^{-5}[a]	3.1×10^{-5}[a]		
Beryllium			9.5×10^{-6}[a]	9.5×10^{-6}[a]		
Cadmium			[b]	5.3×10^{-5}		
Chromium		1.1×10^{-2}	[b]	3.6×10^{-3}	1.6×10^{-2}	
Copper	1.9×10^{-2}	1.1×10^{-1}	3.5×10^{-1}	9.5×10^{-3}	3.5×10^{-1}	9×10^{-3}
Cyanide						
Lead			[b]	7.6×10^{-4}		
Mercury			[b]	1.4×10^{-6}		
Nickel	1.1×10^{-1}	6.5×10^{-2}	4.5×10^{-4}	1.5×10^{-1}	2.6×10^{-1}	4.7×10^{-3}
Selenium			1.9×10^{-6}[a]	1.9×10^{-6}[a]		
Silver			9.5×10^{-6}	1.9×10^{-5}		
Thallium						
Zinc	3.7×10^{-1}	1.1×10^{-1}	4.4×10^{-4}	1.9×10^{-2}	3.9×10^{-1}	7.6×10^{-3}
Classical parameters						
TDS		6.3×10^{1}	5.9×10^{-1}		2.9×10^{1}	
TSS		2.0×10^{-2}	6.5×10^{-2}	2.9×10^{-2}	2.3	
COD			6.2×10^{-2}	1.4		
TOC				2.1×10^{-1}		
Oil and grease		3.8×10^{-2}	3.8×10^{-3}	1.4×10^{-2}		
Phenols				2.9×10^{-5}		
NH_3-N		4.9	1.3	1.8×10^{-1}[a]		
Org-N			2.4×10^{-2}[a]	1.0×10^{-1}[a]		
NO_2+NO_3-N			2.6×10^{-4}[a]	9.5×10^{-6}[a]		
Silica	3.8×10^{-2}[a]	8.9×10^{-2}[a]	1.0×10^{-2}[a]	6.3×10^{-2}[a]	1.5×10^{-1}[a]	
Bromide			2.7×10^{-2}[a]			
Chloride			5.7×10^{-2}[a]			
Fluoride			3.6×10^{-3}[a]			
Sulfate				9.5×10^{-4}		
Other pollutants						
Aluminum		2.9×10^{-2}	[b]	6.0×10^{-3}		
Barium			5.7×10^{-5}	1.5×10^{-4}		
Calcium		8.6×10^{-3}	[b]	3.3×10^{-2}	4.7×10^{-1}	
Iron	9.3	6.6	[b]	2.7	3.7	4.4
Manganese		5.8×10^{-2}	2.8×10^{-5}	2.0×10^{-2}	7.8×10^{-3}	
Magnesium		4.7×10^{-3}	[b]	[b]		
Phosphorus	1.9×10^{-1}	2.5×10^{-1}	1.9×10^{-2}	3.8×10^{-2}	1.9×10^{-1}	
Potassium			1.4×10^{-1}[a]	1.6×10^{-3}[a]		
Sodium		3.3×10^{-1}	[b]	2.1×10^{-2}		
Tin			9.0×10^{-4}	1.8×10^{-3}		

Note: The median flow rate from Table 38 is 870 m^3/d. This was determined by multiplying the volume per cleaning by the number of cleanings per year and dividing by 365. The same flow rate is assumed for all types of tube washes.

[a] Value was calculated assuming zero concentration in the inlet water to provide a worst case analysis.

[b] The median intake concentration is greater than the median discharge concentration.

TABLE 43. EFFLUENT FACTORS FOR MAINTENANCE CLEANING OF BOILER FIRESIDE AND AIR PREHEATER

	Effluent factors, g/kg		
Parameter	Boiler fireside wash water	Air preheater wash water	Air preheater and fireside wash
Toxic pollutants			
Cadmium		2.7×10^{-4}	
Chromium	1.6×10^{-5}	5.8×10^{-5}	8.5×10^{-3}
Copper	6.5×10^{-5}		8.6×10^{-3}
Lead			2.6×10^{-2}
Nickel	7.6×10^{-4}	9.4×10^{-4}	5.5×10^{-3}[a]
Zinc	4.3×10^{-5}	5.2×10^{-5}	4.0×10^{-2}[a]
Classical parameters			
TDS	5.0×10^{-2}	1.6×10^{-2}	
TSS	2.7×10^{-3}	1.4×10^{-3}	
COD		2.4×10^{-3}	
Chloride		8.5×10^{-4}[a]	
Sulfate	1.1×10^{-2}[a]	1.0×10^{-1}[a]	
Oil and grease	–[b]	1.1×10^{-5}[a]	
Other pollutants			
Aluminum	1.6×10^{-5}		
Calcium		4.5×10^{-4}	
Iron	2.7×10^{-2}	2.1×10^{-2}	
Magnesium		1.4×10^{-2}	
Manganese	3.8×10^{-5}		
Sodium		1.6×10^{-2}	

Note: Blanks indicate data not available.

[a] Value based on a zero inlet concentration.

[b] Outlet concentration is below the detection limit.

TABLE 44. EFFLUENT FACTORS FOR HANDLING OF FLY ASH AND BOTTOM ASH

Pollutant	Bottom ash effluent factor	Fly ash effluent factor
Toxic pollutants		
Antimony	7.8×10^{-6}	
Arsenic	3.5×10^{-5}[a]	
Beryllium	3.9×10^{-6}[a]	
Cadmium	0[b]	1.4×10^{-3}
Chromium	0[b]	–[c]
Copper	3.9×10^{-5}	–[c]
Cyanide	5.9×10^{-5}	
Lead	0[b]	5.0×10^{-4}
Mercury	0[b]	
Nickel	2.0×10^{-5}	–[d]
Selenium	2.4×10^{-5}	
Silver	8.3×10^{-6}	
Thallium	–[d]	
Zinc	1.2×10^{-5}	9.0×10^{-3}
Phthalates		
Bis(2-ethylhexyl) phthalate	2.4×10^{-5}	3.3×10^{-4}[a]
Butyl benzyl phthalate	>0	
Di-n-butyl phthalate	1.0×10^{-4}	3.1×10^{-5}
Phenols		
2,4-Dichlorophenol	2.3×10^{-4}	
2,4-Dinitrophenol	9.8×10^{-5}	
Pentachlorophenol	1.0×10^{-4}[a]	
Phenol	7.9×10^{-6}	–[c]
Aromatics		
1,2-Dichlorobenzene	2.2×10^{-4}	4.9×10^{-4}
1,3-Dichlorobenzene	2.2×10^{-4}	4.9×10^{-4}
1,4-Dichlorobenzene	2.2×10^{-4}	4.9×10^{-4}
Polycyclic aromatic hydrocarbons		
2-Chloronapthalene	2.0×10^{-4}[a]	
POM (total)		1.5×10^{-5}[e]
Halogenated aliphatics		
1,2-Dichloroethane	1.1×10^{-4}[a]	
Methylene chloride	6.9×10^{-2}	7.6×10^{-2}[a]

Note: The bottom ash flow rate is 3,600 m^3/d and the fly ash flow rate is 14,420 m^3/d.

[a] Inlet concentration was taken as zero to provide a "worst case" analysis.

[b] Inlet and outlet median concentrations are equal.

[c] Intake concentrations exceed outlet concentrations.

[d] Inlet and outlet median concentrations are below detectable limits.

[e] Based on average concentrations in Appendix D of <1 mg/m^3.

TABLE 45. EFFLUENT FACTORS FOR SETTLING POND EFFLUENT FROM NONREGENERABLE FGD PROCESSES

Parameter	Effluent factor, g/kg
Toxic pollutants	
Arsenic	7.2×10^{-5}
Lead	6.1×10^{-5}
Mercury	1.3×10^{-6}
Selenium	2.9×10^{-5}
Classical parameters	
TDS	8.4
TSS	0.10
COD	0.10
$CaCO_3$ (alkalinity)	0.37
Chloride	[illegible].0
Sulfate	2.7
Sulfite	0.81
Other pollutants	
Boron	0.091
Calcium	3.3
Magnesium	0.11
Sodium	0.91

swimming, etc.) or for drinking. Information on the environmental effects and eventual fate of most pollutant species is readily available in the literature [97, 98].

The potential for environmental damage resulting from the discharge of effluents from the operation of pulverized bituminous coal-fired dry bottom utility boilers is evaluated in a manner analogous to that used to evaluate the effects from air emissions. An average source is defined, and pollutant concentrations are determined for the effluent after dispersion into an average river. The pollutant concentrations are then compared to water quality criteria to determine the effluent severity.

Ambient Effluent Severity

Effluent source severities represent a comparison of the pollutant concentrations occurring in a natural water system as a result of wastewater discharges to ambient environmental goals. These goals are equal to water quality criteria [98] when available or to aquatic toxicity data. The ambient effluent severity, S_e, is defined as follows:

$$S_e = \frac{V_D\ C_D}{(V_D + V_R)F_e}$$

where V_D = effluent stream discharge rate, m^3/d

C_D = concentration of a pollutant in the effluent, g/m^3

V_R = average river flow rate, m^3/d

F_e = ambient environmental goal = water quality criterion when available, g/m^3

or otherwise = 0.01 LC_{50} (96 hr) for the organism with the least tolerance (where LC_{50} [96-hr] is the concentration of a chemical species that is lethal to 50% of the test organisms in a 96-hr test period), g/m^3

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[97] Klein, L. River Pollution II: Causes and Effects. Butterworth and Co., Limited. London. England, 1962. 456 pp.

[98] Quality Criteria for Water. EPA-440/9-76-023 (PB 263 943), U.S. Environmental Protection Agency, Washington, D.C., July 1976. 501 pp.

A derivation and explanation of the ambient severity term is presented in Appendix C. Environmental goals used in determining severities are listed in Table 46 [98-101].

By assuming the discharge rate to be much smaller than the river flow rate, the ambient severity equation can be modified as follows:

$$S_e = \frac{EF/1.0919 \times 10^{-6}}{V_R \cdot F_e}$$

where EF = effluent factor, g/kg coal
1.0919×10^{-6} = 1/coal consumption rate, d/kg coal

The average river flow rate, 1.29×10^{8} m^3/d, was obtained from plant specific data from Reference 96. By comparison the average river flow rate for dry bottom industrial boilers firing pulverized bituminous coal was found to be 6.3×10^{8} m^3/d [3]. This indicates that utility boilers tend to be situated on larger rivers than industrial boilers.

Some of the ambient severities, like the effluent factors, were calculated to provide a "worst case" analysis, and these severities can be expected to be higher than the true values. Ambient effluent severities are listed in Tables 47 through 53. All severities were determined to be less than 1.0, and most were less than 0.01. All severities >0.05 were from cleaning operations that take place once every 1 to 12 years.

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[99] Reznik, R. B., E. C. Eimutis, J. L. Delaney, S. R. Archer, J. C. Ochsner, W. R. McCurley, and T. W. Hughes. Source Assessment: Prioritization of Stationary Water Pollution Sources. EPA-600/2-78-004q (PB 285 421), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, July 1978. 137 pp.

[100] Water Quality Criteria; Availability. Federal Register, 44:15,925-15,981; 43,659-43,697; 56,628-56,657, 1979.

[101] Supplement to Development Document: Hazardous Substances Regulations, Section 311 of the Federal Water Pollution Control Act as Amended 1972. EPA-440/9-75-009 (PB 258 514), U.S. Environmental Protection Agency, Washington, D.C., November 1975. 783 pp.

TABLE 46. EFFLUENT ENVIRONMENTAL GOALS [99-101]

Parameter	Hazard factor, g/m³	Parameter	Hazard factor, g/m³
Toxic pollutants[a]		Toxic pollutants[a] (continued)	
Antimony	1.2×10^{-1}	Pentachlorophenol	6.2×10^{-3}
Arsenic	5.7×10^{-2}	Phenol	0.6
Beryllium	4.3×10^{-4}[b]	Polychlorinated biphenyls (PCB's)	1.5×10^{-6}
Cadmium	6.9×10^{-4}[b]	Polycyclic organic materials (POM's)[g]	9.7×10^{-3}[c]
Chromium (+3)	8.6×10^{-1}[b]	Tetrachloroethylene	3.1×10^{-1}
Chromium (+6)	1.0×10^{-2}	Toluene	2.3
Copper	2.9×10^{-3}[b]	1,2,4-Trichlorobenzene	2.1×10^{-1}
Cyanide	1.4×10^{-3}	1,1,1-Trichloroethane	5.3
Lead	3.6×10^{-2}[b]	2,4,6-Trichlorophenol	5.2×10^{-2}
Mercury (inorganic)	6.4×10^{-5}		
Nickel	3.8×10^{-2}[b]	Classical parameters	
Selenium	9.7×10^{-3}	Alkalinity	2.0×10^{1}
Silver	9.0×10^{-6}	Bromide	7.9
Thallium	4.0×10^{-3}[c]	Chloride	2.5×10^{2}
Zinc	4.3×10^{-2}[b]	Fluoride	1.9×10^{-1}
Acenaphthylene	1.1×10^{-1}[d]	Nitrate	1.0×10^{1}
Benzene	3.1	Oil and grease	1.0×10^{-2}
Butyl benzyl phthalate	5.0[e]	Sulfate	2.5×10^{2}
Chlorodibromomethane	1.4×10^{-1}[f]	TDS	2.5×10^{2}
Chloroform	5.0×10^{-1}	TOC	2.8×10^{2}
Di-n-butyl phthalate	5.0[c]	TSS	2.5×10^{1}
1,2-Dichlorobenzene	4.4×10^{-2}		
1,3-Dichlorobenzene	3.1×10^{-1}	Other pollutants	
1,4-Dichlorobenzene	1.9×10^{-1}	Aluminum	8.3
1,2-Dichloroethane	3.9	Barium	1.0
1,1-Dichloroethylene	5.3×10^{-1}	Calcium	1.6
2,4-Dichlorophenol	3.0×10^{-3}	Iron	3.0×10^{-1}
Di-2-ethylhexyl phthalate	1.0×10^{1}	Magnesium	5.2×10^{-1}
Diethyl phthalate	6.0×10^{1}	Manganese	5.0×10^{-2}
2,4-Dinitrophenol	7.9×10^{-2}	Phosphorus[h]	1.0×10^{-1}
Di-n-octyl phthalate	5.0[e]	Potassium	6.8
Ethyl benzene	1.1[c]	Sodium	2.5×10^{2}
Methylene chloride	4.0		

[a] Pollutants listed as toxic under the Clean Water Act (see Reference 99). Values given are 24-hour average concentrations for freshwater aquatic life.

[b] Based on receiving water hardness of 100 g/m³.

[c] Drinking water standard.

[d] Value for acenaphthene.

[e] Value for di-n-butyl phthalate.

[f] Value for bromomethane.

[g] Also known as polynuclear aromatic hydrocarbons (PAH's).

[h] Value for phosphate.

TABLE 47. EFFLUENT SEVERITIES FOR CONDENSER COOLING SYSTEMS

Pollutant	Once-through cooling systems	Recirculated cooling water systems
Metals		
Arsenic		2.0×10^{-7}
Copper	7.8×10^{-3}	1.5×10^{-5}
Cyanide		2.6×10^{-5}
Mercury	9.8×10^{-3}	
Nickel	2.6×10^{-3}	6.4×10^{-7}
Silver		3.5×10^{-4}
Zinc		8.3×10^{-6}
Phthalates		
Butyl benzyl phthalate	1.1×10^{-5}	
Di-n-butyl phthalate	3.4×10^{-6}	
Di-2-ethylhexyl phthalate	1.2×10^{-5}	1.8×10^{-10}
Diethyl phthalate	1.0×10^{-6}	
Di-n-octyl phthalate	1.1×10^{-5}	
Phenols		
Phenol (total)	1.9×10^{-4}	
2,4,6-Trichlorophenol		3.5×10^{-7}
Aromatics		
Benzene		2.7×10^{-8}
1,2-Dichlorobenzene	2.6×10^{-4}	4.2×10^{-7}
1,3-Dichlorobenzene	3.7×10^{-5}	6.0×10^{-8}
1,4-Dichlorobenzene	6.0×10^{-5}	9.7×10^{-8}
Polycyclic aromatic hydrocarbons		
2-Chloronaphthalene	2.0×10^{-3}	
Halogenated aliphatics		
Bromoform	2.3×10^{-3}	1.8×10^{-7}
Chlorodibromomethane		7.6×10^{-7}
1,1-Dichloroethylene	1.7×10^{-4}	
Methylene chloride	3.9×10^{-3}	7.1×10^{-7}
Tetrachloroethylene	1.4×10^{-3}	
1,1,1-Trichloroethane	1.3×10^{-5}	6.3×10^{-9}

Note: Blanks indicate data are not available or severities are equal to zero.

TABLE 48. EFFLUENT SEVERITIES FOR BOILER FEEDWATER TREATMENT

Parameter	Clarification discharge	Softening discharge	Ion discharge	Evaporation discharge	Filtration[a] discharge	Other discharge
Toxic pollutants						
Chromium		6.6×10^{-6}	1.5×10^{-6}	3.1×10^{-6}	1.2×10^{-3}	
Copper		2.9×10^{-5}	8.8×10^{-7}	3.7×10^{-4}	9.1×10^{-3}	
Nickel		8.4×10^{-7}			2.1×10^{-4}	
Zinc		1.5×10^{-6}	8.4×10^{-8}	1.1×10^{-4}		
Chloroform					3.3×10^{-6}	1.4×10^{-5}
Ethyl benzene						5.6×10^{-7}
Toluene					4.9×10^{-5}	6.2×10^{-6}
Classical parameters						
TDS		1.9×10^{-6}		7.1×10^{-6}		
TSS		5.1×10^{-5}	2.2×10^{-7}	1.7×10^{-6}		
Oil and grease		8.0×10^{-4}		4.3×10^{-5}		
Bromide			3.4×10^{-8}			
Chloride			1.8×10^{-6}	6.5×10^{-7}		
Sulfate			2.3×10^{-8}	2.7×10^{-7}		
Other pollutants						
Iron	9.2×10^{-4}	1.8×10^{-5}				
Sodium			3.4×10^{-6}			

Note: Blanks indicate data are not available or severities are equal to zero.

[a] Data based on only one plant.

TABLE 49. EFFLUENT SEVERITIES FOR BOILER BLOWDOWN

Parameter	Severity
Toxic pollutants	
Chromium	6.0×10^{-7}
Copper	1.0×10^{-5}
Classical parameter	
Oil and grease	7.0×10^{-4}
TDS	1.5×10^{-6}
TSS	1.8×10^{-7}

TABLE 50 EFFLUENT SEVERITIES FOR MAINTENANCE CLEANING OF BOILER OR GENERATOR TUBES

Parameter	Ammoniated critic acid discharge	Ammoniated AOTA	Ammoniated sodium bromate discharge	HCl without Cu complexer discharge	HCl with Cu complexer discharge	Hydroxyacetate/formic acid discharge
Toxic pollutants						
Arsenic			5.7×10^{-6}	5.4×10^{-4}		
Beryllium			1.6×10^{-4}	1.6×10^{-4}		
Cadmium				5.5×10^{-4}		
Chromium		7.8×10^{-3}		2.6×10^{-3}	1.1×10^{-2}	
Copper	4.7×10^{-2}	2.7×10^{-1}	8.6×10^{-1}	2.3×10^{-3}	8.6×10^{-1}	4.7×10^{-3}
Lead				1.6×10^{-4}		
Mercury				1.5×10^{-4}		
Nickel	2.1×10^{-2}	1.2×10^{-2}	8.4×10^{-5}	2.8×10^{-2}	4.9×10^{-2}	8.8 x 10[illegible]
Selenium			1.4×10^{-6}	1.4×10^{-6}		
Silver			7.5×10^{-3}	1.5×10^{-2}		
Zinc	6.[illegible] x 10^{-2}	1.8×10^{-2}	7.3×10^{-5}	3.1×10^{-3}	6.4×10^{-2}	1.3×10^{-3}
Other pollutants						
Aluminum		2.5×10^{-5}		5.1×10^{-6}		
Barium			4.0×10^{-7}	1.1×10^{-6}		
Calcium		3.8×10^{-5}		1.5×10^{-4}	2.1×10^{-3}	
Iron	2.2×10^{-1}	1.6×10^{-1}		6.4×10^{-2}	8.8×10^{-2}	[illegible].0 x 10^{-1}
Manganese		8.2×10^{-3}	4.0×10^{-6}	2.8×10^{-3}	1.1×10^{-3}	
Magnesium		6.4×10^{-5}				
Phosphorus	1.3×10^{-4}	1.8×10^{-2}	1.3 x 10[illegible]	2.7×10^{-3}	1.3×10^{-2}	
Potassium			1.5×10^{-4}	1.7×10^{-6}		
Classical pollutants						
TDS		1.8×10^{-3}	1.7×10^{-5}		8.2×10^{-4}	
TSS		5.7×10^{-6}	1.8×10^{-5}	8.2×10^{-6}	6.5×10^{-4}	
TOC				5.3×10^{-5}		
Oil and grease		2.7×10^{-2}	2.7×10^{-3}	9.9×10^{-3}		
Bromide			2.4×10^{-6}			
Chloride			1.6×10^{-6}			
Fluoride			1.3×10^{-4}			

Note: Blanks indicate data are not available or severities are equal to zero.

TABLE 51. EFFLUENT SEVERITIES FOR MAINTENANCE CLEANING OF BOILER FIRESIDE AND PREHEATER

	Effluent severities		
Parameter	Boiler fireside wash water	Air preheater wash water	Air preheater and fireside wash
Toxic pollutants			
Cadmium		2.8×10^{-3}	
Chromium	1.1×10^{-5}	4.1×10^{-5}	6.0×10^{-3}
Copper	1.6×10^{-4}		2.1×10^{-2}
Lead			5.1×10^{-3}
Nickel	1.4×10^{-4}	1.8×10^{-4}	1.0×10^{-3}
Zinc	7.1×10^{-6}	8.6×10^{-6}	6.6×10^{-3}
Other pollutants			
Aluminum	1.4×10^{-8}		
Calcium		2.0×10^{-6}	
Iron	6.4×10^{-4}	5.0×10^{-4}	
Magnesium		1.9×10^{-4}	
Manganese	5.4×10^{-6}		
Sodium		4.5×10^{-7}	
Classical parameters			
TDS	1.4×10^{-6}	4.5×10^{-7}	
TSS	7.7×10^{-7}	4.0×10^{-7}	
Chloride		2.4×10^{-8}	
Sulfate	3.1×10^{-7}	2.8×10^{-6}	
Oil and grease		7.8×10^{-6}	

Note: Blanks indicate data are not available or severities are equal to zero.

TABLE 52. EFFLUENT SEVERITIES FOR HANDLING OF FLY ASH AND BOTTOM ASH

Pollutant	Bottom ash	Fly ash
Toxic pollutants		
Antimony	4.6×10^{-7}	
Arsenic	4.4×10^{-6}	
Beryllium	6.4×10^{-5}	
Cadmium		1.4×10^{-2}
Copper	9.5×10^{-5}	
Cyanide	3.0×10^{-4}	
Lead		9.9×10^{-5}
Nickel	3.7×10^{-6}	
Selenium	1.8×10^{-5}	
Silver	6.5×10^{-3}	
Zinc	2.0×10^{-6}	1.5×10^{-3}
Phthalates		
Di-2-ethylhexyl phthalate	1.7×10^{-8}	2.3×10^{-7}
Di-n-butyl phthalate	1.4×10^{-7}	4.4×10^{-8}
Phenols		
2,4-Dichlorophenol	5.4×10^{-4}	
2,4-Dinitrophenol	8.8×10^{-6}	
Pentachlorophenol	1.1×10^{-4}	
Phenol	9.3×10^{-8}	
Aromatics		
1,2-Dichlorobenzene	3.5×10^{-5}	7.9×10^{-5}
1,3-Dichlorobenzene	5.0×10^{-6}	1.1×10^{-5}
1,4-Dichlorobenzene	8.2×10^{-6}	1.8×10^{-5}
Polycyclic aromatic hydrocarbons		
2-Chloronaphthalene	4.9×10^{-5}	
POM (total)		1.1×10^{-5}
Halogenated aliphatics		
1,2-Dichloroethane	2.0×10^{-7}	
Methylene chloride	1.2×10^{-4}	1.3×10^{-4}

Note: Blanks indicate data are not available or severities are equal to zero.

TABLE 53. EFFLUENT SEVERITIES FOR SETTLING POND EFFLUENT FROM NONREGENERABLE FGD PROCESSES

Parameter	Effluent severities
Toxic pollutants	
Arsenic	8.9×10^{-6}
Lead	1.2×10^{-5}
Mercury	1.4×10^{-4}
Selenium	2.1×10^{-5}
Classical parameters	
TDS	2.4×10^{-4}
TSS	2.8×10^{-6}
$CaCO_3$	1.3×10^{-4}
Chloride	8.5×10^{-5}
Sulfate	7.6×10^{-5}
Other Pollutants	
Boron	8.6×10^{-4}
Calcium	1.5×10^{-2}
Magnesium	1.5×10^{-3}
Sodium	2.5×10^{-5}

WASTEWATER TREATMENT

Neutralization is the principal method of wastewater treatment used for utility boilers; it is followed by controlled release to a waterway to achieve a dilution of 5,000:1 to 10,000:1 [16]. Depending on the space available and the nature of other wastewater streams generated at the site, a holding pond may be used to permit sedimentation; if climatic conditions are favorable, an evaporation pond may be utilized alternatively. Other options include off-site treatment and disposal by a commercial waste disposal firm, ocean dumping, and solidification of wastes by an outside vendor for land disposal. However, these methods are costly and not often employed. Low volume waste streams such as those from feedwater treatment, boiler blowdown, cooling water for fan bearings, steam condensate from the pneumatic ash transport system and miscellaneous equipment cleaning are usually mixed with the process waste streams; otherwise they are discharged to a municipal sewer system. The unit operations of a plant's treatment system are determined by the nature of the process wastes.

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SECTION 6

SOLID WASTES AND CONTROL TECHNOLOGY

SOURCES AND COMPOSITION

Coal ash generated in the furnace by combustion constitutes the major source of solid wastes from utility boilers. An estimated 4.3×10^7 metric tons of ash are collected annually from this source [2]. Other potential solid waste sources are the sludges created by the softening of boiler feed water using lime and soda ash, and by the operation of most SO_x scrubbers.

Coal Ash

Bituminous coal contains 4% to 15% inorganic ash. On combustion, the ash content is distributed between bottom ash and fly ash. Bottom ash consists of the heavier particles which fall to the bottom of the furnace. Such ash either accumulates on the floor of the furnace for periodic removal or is collected in a hopper fitted to the furnace bottom. The remaining ash is entrained in the combustion gas stream. The distribution between bottom ash and fly ash is a function of boiler type. Table 54 presents the average distribution of bottom ash to fly ash for the defined source type and for other boiler types for comparison [2].

TABLE 54. DISTRIBUTION OF COAL ASH BY BOILER TYPE [2]

Boiler type	Percent distribution of bottom ash to fly ash
Pulverized dry bottom	15:85
Pulverized wet bottom	35:65
Cyclone	90:10
Stoker	65:35

Because dry bottom boilers produce primarily fly ash, it is clear that the major factor influencing the quantity of ash to be discarded is the extent of particulate control. NEDS data show that 86% of the boilers in this catagory are equipped with controls which have collection efficiencies ranging from below 50% to 99+% [6].

Typical physical properties of coal ash from pulverized coal-fired plants are presented in Table 55. Differences in the physical properties of bottom ash and fly ash are minor; these result from slight differences in trace metal content due to element partioning and from a higher carbon content in the fly ash.

TABLE 55. TYPICAL PHYSICAL PROPERTIES OF FLY ASH FROM PULVERIZED COAL-FIRED PLANTS [102]

Constituent	Range
pH	6.5 to 4.5
Particle size range, μm	0.5 to 100
Average percent of particles passing 325-mesh sieve, (44 μm), %	60 to 90
Bulk density (compacted), kg/m^3	1,100 to 1,300
Specific gravity	2.1 to 2.6
Specific area per gram, cm^2/g	3,300 to 6,400

The specific chemical composition of a coal ash is dictated by the geology of the coal deposit and the boiler operating parameters. Coal ash is primarily an iron-aluminum silicate with additions of lime, magnesia, sulfate, sodium and potassium oxides, carbon, and traces of heavy metals. A detailed listing of the chemical constituents of coal ash, showing the average composition and the composition range, is provided in Table 56 [103]. Because of the high temperature at which most coal ash is formed, a glassy phase is produced which can account for up to 90% of the ash structure. Other crystal phases often encountered in ash include mullite, quartz, hematite, and magnetite. The distribution of these mineral phases is shown in Table 57 [103].

Lime - Soda Ash Softening Sludge

Water destined for boiler use is treated using the lime - soda ash softening process which produces a solid sludge waste. However, the extent to which this softening process is used for the treatment of boiler feedwaters for the source type being studied

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[102] Ash Utilization. Bureau of Mines Information Circular IC8488, U.S. Department of the Interior, Washington, D.C., 1970. 351 pp.

[103] Hecht, N. L., and D. S. Duvall. Characterization and Utilization of Municipal and Utility Sludges and Ashes; Volume III - Utility Coal Ash. EPA-670/2-75-033c (PB 244 312), U.S. Environmental Protection Agency, Cincinnati, Ohio, May 1975. 74 pp.

TABLE 56. CHEMICAL CONSTITUENTS OF COAL ASH [103]

	Composition	
Constituents	Range, %	Average, %
Silica	20 to 60	48
Alumina	10 to 35	26
Ferric oxide	5 to 35	15
Calcium oxide	1 to 20	5
Magnesium oxide	0.25 to 4	2
Titanium dioxide	0.5 to 2.5	1
Potassium oxide[a]	1.0 to 4.0	2
Sodium oxide[a]	0.4 to 1.5	1
Sulfur trioxide	0.1 to 12	2
Carbon	0.1 to 20	4
Boron	0.01 to 0.6	–[b]
Phosphorus	0.01 to 0.3	
Manganese	0.01 to 0.3	
Molybdenum	0.01 to 0.1	
Zinc	0.01 to 0.2	
Copper	0.01 to 0.1	
Mercury	0.0 to 0.02	
Uranium and thorium	0.0 to 0.1	

[a] Alkalies.

[b] Blanks indicate average not reported.

TABLE 57. MINERAL PHASES FOUND IN COAL ASH [103]

Phase	Percent
Quartz	0 to 4
Mullite	0 to 16
Magnetite	0 to 30
Hematite	1 to 8
Glass	50 to 90

is unknown. The softening process reduces hardness by precipitating calcium and magnesium ions; the resulting sludge contains calcium sulfate, calcium carbonate, calcium bicarbonate, magnesium hydroxide, and magnesium carbonate as principal constituents. Minor components are adsorbed onto the solids or entrained in them and may include any material present in the raw water. The quantity of sludge generated by the softening depends on the rate of boiler-water usage and the hardness of the influent water.

Flue Gas Desulfurization Sludge

Boilers equipped with nonregenerable flue gas desulfurization (FGD) processes for controlling SO_x emissions generate a solid-waste stream consisting primarily of a calcium sulfate sludge. Their current usage for SO_x control is limited and includes only about 20 systems for this source type as defined [6]. However, as SO_2 emission standards become more stringent, this process will become a major control method. Widespread use of nonregenerable FGD processes could potentially double the volume of solid wastes generated by utility boilers.

Waste products from FGS systems vary in composition according to the particular process used but generally contain calcium sulfate, calcium sulfite, and coal ash. Approximately 4 kg to 6 kg of sludge are produced for each kilogram of SO_x removed.

DISPOSAL OF WASTE SOLIDS

Treatment and Disposal Practices

In large utilities, the disposal of waste solids may receive considerable attention during the early design of the power plant. In fact, the need for waste disposal may be a primary factor in locating a power plant at a specific site where impoundment of ash and sludge is possible. Approximately 80% of coal-fired utility boilers, based on fuel consumption, use ponding as a method of ash disposal while the remaining 20% use landfill operations.

Coal ash collected in an electrostatic precipitator, baghouse, bottom hopper, or other unit is moved to on-site facilities for temporary storage using water sluicing, gravity flow, or pneumatic transport. From the storage facilities, which usually consist of an ash holding pond or hopper, the ash is loaded onto trucks using dredging, pumping, or gravity flow and removed for disposal or resource recovery.

Depending on the type of ash collection devices and the on-site ash handling and storage facilities, the ash may be delivered to the disposal area either wet or dry. Generally, the ash is not

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treated per se prior to disposal. However, ash stored in a holding pond receives some treatment in that a portion of the soluble material is removed thus lessening the potential leaching effects.

Sludges resulting from water softening processes can be discarded by direct discharge to rivers or sewer systems; however, these disposal methods are regulated and limited by NPDES permits and agreements with the local wastewater treatment authorities, respectively. A more acceptable disposal practice consists of either sending the sludge to a pond as it comes from the process containing about 5% solids, or sending it to a landfill site after filtering, drying or other thickening operations have been performed.

The use of ponds and landfills presently represent the major options for FGD sludge disposal. Both methods are being utilized with and without sludge fixation. Lined and unlined ponds are being used [104]. In anticipation of the large FGD sludge volumes expected in the future, the government is currently evaluating the possibility of using mine and ocean disposal for these materials [105].

Most sludges generated in SO_x scrubbers contain calcium sulfite hemihydrate ($CaSO_3 \cdot 1/2\ H_2O$), which is responsible for the moisture retaining character and thixothropic behavior of the sludge. Because these sludges are difficult to dewater and have little or no compressive strength, they may be unsuitable for landfill unless chemically treated (via fixation). Three companies currently market sludge fixation technologies [106]. These processes involve treatment of sludges with various chemicals to produce a material with sufficient compressive strength for landfill use and to chemically and/or physically bind up the soluble constituents of the sludges. Table 58 indicates the differences in elemental concentrations observed for raw sludge and for leachate from fixed sludge [107].

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[104] Jones, J. W. Environmentally Acceptable Disposal of Flue Gas Desulfurization Sludges; The EPA Research and Development Program. In: Proceedings: Symposium of Flue Gas Desulfurization--Atlanta, November 1974, Volume II. EPA-650/2-74-126b (PB 242 573), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, December 1974. 511 pp.

[105] Lunt, R. R., C. V. Cooper, S. L. Johnson, J. E. Oberholtzer, G. R. Schimke, and W. I. Watson. An Evaluation of the Disposal of Flue Gas Desulfurization Wastes in Mines and the Ocean: Initial Assessment. EPA-600/7-77-051 (PB 269 270), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, May 1977. 318 pp.

[106] Rossoff, J., R. C. Rossi, L. J. Bornstein, and J. W. Jones. Disposal of By-products from Non-Regenerable Flue Gas Desulfurization Systems - A Status Report. In: Proceedings: Symposium on Flue Gas Desulfurization--Atlanta, November 1974, Volume I. EPA-650/2-74-126a (PB 242 572), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, December 1974. 661 pp.

TABLE 58. TRACE ELEMENTS PRESENT IN RAW SO_x SCRUBBER SLUDGE AND IN LEACHATE FROM SLUDGE AFTER FIXATION [107]

Constituents	Raw sludge, ppm	Leachate from conditioned sludge, ppm
Arsenic	2.2	<0.10
Cadmium	0.30	<0.10
Chlorides	2,000	64.0
Chromium (total)	2.8	<0.25
Copper	1.5	<0.10
Iron	120	<0.10
Lead	26	<0.10
Mercury	<0.10	<0.10
Nickel	3.5	<0.10
Zinc	16	<0.10
Phenol	<0.25	<0.10
Cyanide	<0.10	<0.10
Sulfate	<10,000	400

Resource Recovery

Stimulated by the large quantities of coal ash generated annually, research efforts in resource recovery have led to the development of numerous potential applications. At the present time, however, the supply greatly exceeds the demand although there is a trend toward increased utilization [103].

Approximately 12% of the coal burned in a boiler is reclaimed as coal ash residue existing mainly (50%-90%) in the glassy state. The most abundant application for the use of these ashes is as mineral fill for roads and other construction products. In Europe, residual ash has also prominently been used as filler for concrete block. Coal ash can also be utilized as a replacement for cement in concrete and concrete products offering improved mechanical strength and improved resistance to sulfate leaching. Fly ash and boiler slag are also being used as filler in asphalt and for road base stabilization. Boiler slag is especially useful because it increases the skid resistance of asphalt pavements. Coal ash can also be used agriculturally in land and water reclamation. Because its high pH neutralizes mineral soil, coal ash is especially useful for reclaiming surface mine soil and as a soil nutrient [103].

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[107] Rossoff, J., and R. C. Rossi. Disposal of By-Products from Non-Regenerable Flue Gas Desulfurization Systems: Initial Report. EPA-650/2-74-037a (PB 237 114), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, May 1974. 318 pp.

These applications have the potential to utilize the entire quantity of ash produced. Unfortunately, the economic competitiveness of coal ash is impaired by federal practices that favor virgin (natural) materials in freight rates and depletion allowances. Improved federal economic policy toward secondary materials like coal ash would enhance their utilization [103].

After dewatering and treatment, sludge from the lime - soda ash softening process can be reused as a water-softening reagent or used as agricultural lime suitable for direct application. Treatment for reuse involves calcining in a furnace, removal of magnesium hydroxide by centrifuging, or a combination of the two methods [18].

Numerous FGD sludge applications have been identified for potential commercial utilization; these include its use in mineral wool, bricks, sintered concrete products, road base materials, parking lot materials, artificial aggregate, lightweight aggregate, and aerated concrete. In addition, FGD sludge may be used directly as a soil amendment and/or for sulfur and mineral recovery, or it can be converted into gypsum. Although many potential products are anticipated, some of which may be superior to those currently used, several factors exist which could inhibit large-scale sludge usage including its high variable chemical and physical properties, substantial transportation costs (due to rate structures favoring virgin materials), and dewatering requirements.

In Japan, where FGD systems received widespread use, most scrubber sludge is converted into gypsum for reuse in wallboard production or as a cement-setting retardant. Unfortunately, the presence of appreciable quantities of fly ash reduces the market value of wallboard produced in this manner. Because oil is the major combustion fuel in Japan, fly ash is not a problem. For coal-fired sources, a particulate control device such as an ESP would be necessary ahead of the SO_x scrubber in order to remove fly ash and permit the production of a marketable-grade gypsum. Gypsym production may be advantageous in any event because it can be readily dewatered to form a more stable landfill medium, and the volume of material for disposal is thus reduced. Conversion of scrubber sludge to gypsum would also eliminate the chemical oxygen demand exerted by the calcium sulfite.

POTENTIAL ENVIRONMENTAL EFFECTS

For this study, the hazard potential of the solid wastes generated by industrial boilers is assessed by considering that portion of the waste which eventually reaches the open environment as water pollution or air pollution. Water pollution from solid wastes is the result of leaching of pollutants at disposal sites by runoff to groundwater or surface waters. Air emissions result from handling operations, transportation to disposal sites, and wind erosion at disposal sites.

GCA/Technology Division has estimated that air emissions resulting from dry ash handling and disposal are 0.5 kg/metric ton of ash landfill [2]. This estimate was based on wind erosion data which showed that the erosion of soils having particle diameters less than 50 μm is minimal due to the attractive forces between particles and consideration of landfill erosion prevention practices. Using the GCA estimate, the hazard potential associated with air emissions from this point source was determined to be minor in comparison to stack fly-ash emissions. Based on the GCA estimates of fly ash and bottom ash collected for disposal and of stack emissions of noncollected fly ash, and assuming that 20% of the utility ash is used as landfill in dry form, the emissions of ash from handling and disposal total less than 0.2% of the stack ash emissions. In addition, most fugitive ash emissions occur at landfills which are, in general, located in rural areas and at ground level over a large land area; hence, the ash has a higher probability of redepositing on the landfill site.

Contamination of ground water and surface water by pond seepage or runoff containing landfill leachates presents a potential hazard. Leaching studies and ash pond liquor analysis [107, 108] indicate that coal ash and flue gas desulfurization sludges both contain sufficient quantities of soluble toxic materials to pose a threat to the quality of ground water and nearby surface waters. The results of an ash leachate measurement for a bottom ash and fly ash composite from a coal-fired industrial boiler are presented in Table 59 [3].

The magnitude of the environmental impact of ground and surface water pollution from leachates depends on a number of factors which include the chemical and physical nature of the ash and/or

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[108] Holland, W., K. Wilde, J. Parr, P. Lowell, and R. Pohler. Environmental Effects of Trace Elements from Ponded Ash and Scrubber Sludge. EPRI 202 (PB 252 090), Electric Power Research Institute, Palo Alto, California, September 1975. 403 pp.

TABLE 59. ASH LEACHATE DATA [3]

Element[a]	Ash composition, g/kg of ash	Amount of element leached, mg/kg of ash	Percent leached
Aluminum	170	45	0.026
Barium	3.6	2.2	0.059
Boron	1.0	24	2.3
Calcium	49	800	1.8
Magnesium	13	27	0.22
Molybdenum	0.34	5.3	1.6
Sodium	11	210	1.8
Silicon	2.5[b]	9.5	0.38
Strontium	6.2	24	0.39
Vanadium	2.7	4.2	0.16

[a] Elements monitored but not found in leachate include antimony, cadmium, chromium, cobalt, copper, iron, lead, manganese, nickel, phosphorus, silver, tin, titanium and zinc.

[b] Value probably low due to an inability to completely digest silicon for analysis.

sludge, local weather conditions, distance from the disposal site to natural waters, design of the landfill or sludge pond, and the geology of the disposal site and surrounding areas. Most of these factors are site specific and probably unique for a given location. Therefore, no attempt will be made to quantify the potential effects for the average plant. A brief discussion of the findings of other researchers working in this area is presented below.

Leachate characteristics most likely to create a potential hazard are pH, oxygen demand (due to sulfite ion), total dissolved solids (TDS), and concentrations of toxic elements [104, 107-110]. Besides directly affecting the receiving water, the pH value is a primary factor in determining the species and concentrations

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of toxic elements in the leachate [111]. Elements most likely to create a hazard because of their high toxicities and appreciable leaching rates are arsenic, barium, boron, chloride, chromium, lead, mercury, and selenium [105, 107, 108]. On the whole, elemental concentrations actually observed in leachates are low, usually near the analytical detection limits, and the ion-exchange capacities of most soils are adequate for controlling most toxic elements for an extended period (>10 years for 10 m of soil) [108]. In addition, these wastes tend to be self sealing due to the plugging of soil voids by the small particles which are characteristic of ash and sludge.

CONTROL OF EMISSIONS AND EFFLUENTS AT DISPOSAL SITES

As stated above, air and water pollution may result from the handling and disposal of waste solids. The optimum solution for controlling environmental contamination from solids disposal is to eliminate contaminants through recovery for reuse as previously discussed. Emission and effluent abatement methods for the handling and disposal of solids are briefly presented below.

Fugitive emissions from the loading of coal ash onto trucks can be minimized by wetting the coal ash and/or enclosing the transfer point to eliminate losses by wind entrainment and immediately cleaning up any spills that occur. Losses of waste materials during transport to a disposal site can be reduced by covering the ash or sludge after it is put on the truck; this practice is required in some areas. At disposal sites, emissions from wind erosion can be eliminated by adequately covering the disposed solids with earth as soon as possible.

Several methods exist for preventing pollution by leachates and runoff at pond and landfill sites. These methods include the use of liner materials, the construction of a perimeter ditch to collect leachate or runoff for treatment, and chemical fixation and stabilization of solid wastes prior to disposal.

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SECTION 7

FUTURE GROWTH

Since the technological developments of the 1920's which made the use of pulverized coal practical, boilers firing pulverized coal have become the largest source of coal-derived electrical energy. By the mid-1970's, pulverized coal boilers (wet and dry bottom) accounted for 86% of all coal-fired boiler capacity [2]. This percentage is expected to grow still higher because new power plants almost exclusively use pulverized coal firing.

Coal consumption by the utility sector has increased steadily for many decades, even though the proportion of electricity generated from coal has declined. Figure 7 shows the increase in utility coal consumption from 1950 to 1978. Over this same period, the percentage of electrical energy produced from coal dropped from 66% to 59% of the total electrical energy produced by fossil fuels [1].

A renewed interest in the use of coal resulted from the oil producing and exporting countries' (OPEC's) oil embargo of late 1973 which sharply increased oil prices, the recent natural gas shortages, and the inception of government policies directed towards making the United States self-sufficient in energy. President Carter's energy initiative of July 15, 1979, formalized the government's determination to reduce U.S. dependence on foreign oil. This initiative places a heavy emphasis on development of the nation's coal resources and the conversion of oil-fired power plants to coal firing. Coal is an obvious choice as a substitute for oil because coal reserves constitute the largest proven reserves of fossil fuel within the United States.

It is difficult to predict the actual growth of coal-fired generating capacity because of the many opposing factors acting to limit or enhance growth. Projections by the Electric Power Research Institute (EPRI) call for an increase in utility coal consumption from 430 million metric tons in 1978 to over 725 million metric tons in 1985 and over 1.36 billion metric tons by the year 2000 [112]. Some of the major factors that will determine the actual growth rate are summarized on the next page.

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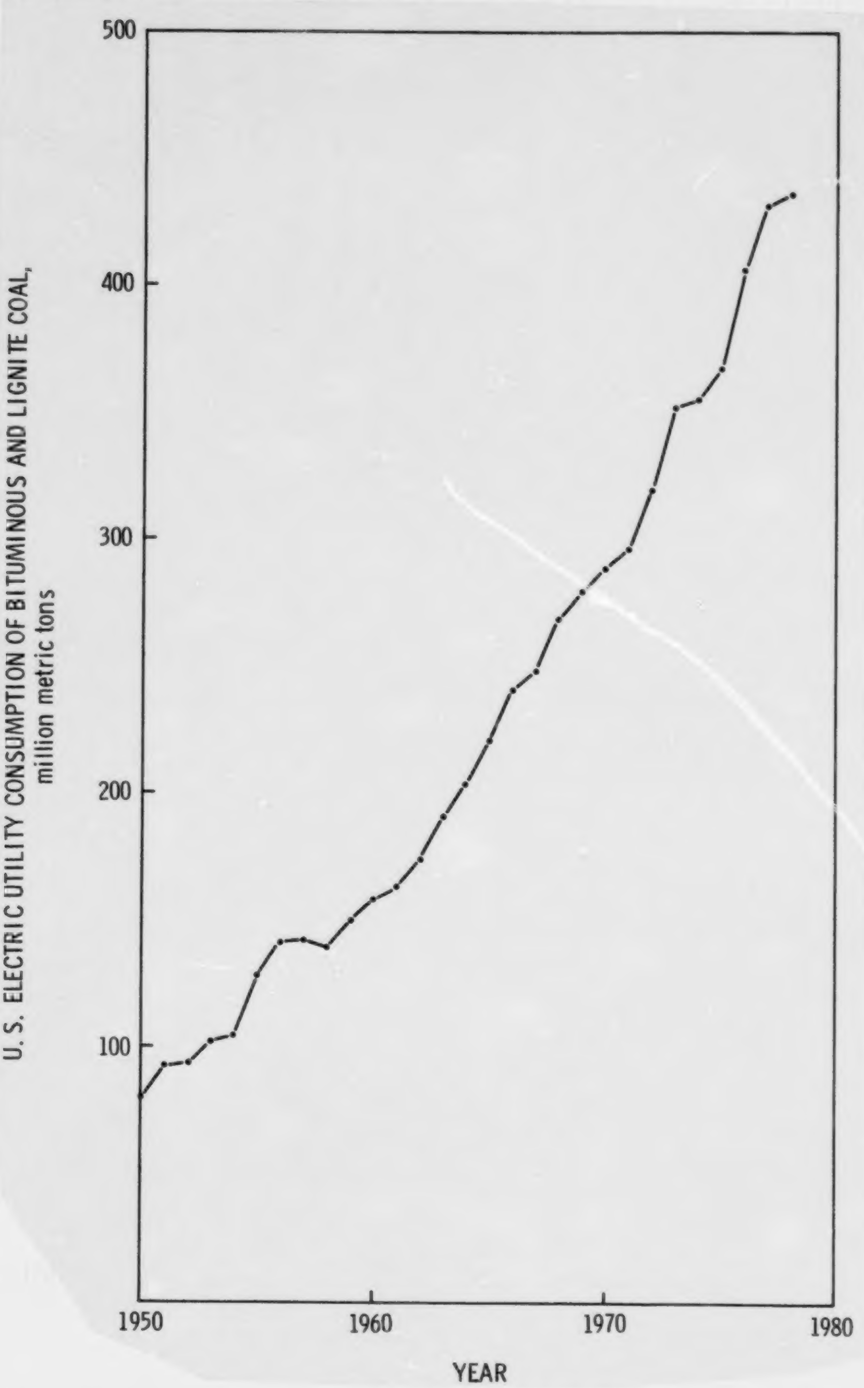

Figure 7. Consumption of bituminous and lignite coals by electric utilities, 1950 - 1978 [1].

Factors Acting to Enhance Growth

- Decreasing supplies and rising costs of oil and natural gas
- Problems that are slowing down the expansion of nuclear power plant capacity
- Government restrictions on the import of foreign oil
- Government incentives or directives toward the use of coal

Factors Acting to Limit Growth

- Environmental regulations on the mining and combustion of coal
- Environmental standards restricting emissions of particulate matter, SO_x, NO_x, CO, hydrocarbons, and POM's
- Cost of required pollution control equipment
- Problem of disposal of wastes from pollution control systems
- Lack of adequate water supplies in the western United States
- Limitations in present railroad capacity for transporting coal
- Public opposition to siting of new power plants
- Increased substitution of solar heat for electric, residential, and commercial heat
- Increased conservation of electric energy use through wider application of computerized load management systems (which have short payoff times with high energy rates), and through other conservation schemes
- The impact of rate structure reform with an emphasis on long run marginal cost based rates

Pollutant emissions from coal-fired power plants are not predicted to increase as rapidly as the coal consumption rate because of increasingly stringent pollution control legislation [48-50].

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114. Lentzen, D. E., D. E. Wagoner, E. D. Estes, and W. F. Gutknecht. IERL-RTP Procedures Manual: Level I Environmental Assessment (Second Edition). EPA-600/7-78-201, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, October 1978. 279 pp.

115. Method 2 - Determination of Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot Tube). Federal Register, 41(111):23063-23069, 1976.

116. Method 4 - Determination of Moisture in Stack Gases. Federal Register, 41(111):23072-23076, 1976.

117. Method 8 - Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sources. Federal Register, 41(111):23087-23090, 1976.

118. Method 3 - Gas Analysis for Carbon Dioxide, Oxygen, Excess Air, and Dry Molecular Weight. Federal Register, 41(111): 23069-23070, 1976.

119. Standard Method of Test for Proximate Analysis of Coal and Coke, Designation D 3172-73. In: 1973 Annual Book of ASTM Standards, Part 19: Gaseous Fuels; Coal and Coke. American Society for Testing and Materials, Philadelphia, Pennsylvania, 1973. p. 434.

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APPENDIX A

DESCRIPTION OF THE SAMPLING PROGRAM

SUMMARY

Sampling was performed on a 970 GJ/hr tangentially-fired, dry bottom unit firing pulverized bituminous coal. Particulate emissions from this unit are trapped by a mechanical collector and a series of two electrostatic precipitators (ESP's). Samples were collected at the outlet of the mechanical collector and the second ESP and sent to MRC's Dayton Laboratory for analysis.

Species that were measured include particulate matter, sulfates (i.e., SO_2, SO_3, H_2SO_4, particulate sulfate), hydrocarbons, polynuclear organic materials (POM's), polychlorinated biphenyls (PCB's), and trace elements (such as As, Pb, Hg, Se, and Cd). Particulate matter, POM's, PCB's, and trace elements were collected with the Source Assessment Sampling System (SASS). The SASS train employs a high flow rate and three cyclones in series to collect particles in four particle size ranges. The combined particulate fractions plus the impinger solutions and organic module condensate were analyzed for trace elements. Additionally, particulates, organic module condensate, and the contents of the XAD-2 organic module were analyzed for POM's and PCB's. Sulfur species and particulate matter were collected using a modified Method 8 train.

Water samples were not collected at this site because of the extensive screening and verification data obtained during EPA's program to establish effluent guidelines for utility boilers [90, 91, 93]. However, water and solid samples collected at another utility boiler site were sent to the Dayton Laboratory for analysis of POM's, PCB's, and trace elements.

SITE DESCRIPTION

The boiler chosen for sampling was a tangentially fired, dry bottom unit burning pulverized Appalachian bituminous coal to produce steam for electricity generation. The boiler has a design firing capacity of 970 GJ/hr and an output capacity of 590,000 kilograms of steam per hour at 12.4 MPa and 540°C. Steam produced by this boiler and a similar unit is used to drive a 180 MW electricity generating turbine.

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7122

Air emissions from this boiler are controlled by a mechanical collector (MC), and two ESP's in series. The particulate control system has an overall collection efficiency of 99.97%. Figure A-1 illustrates the boiler system showing the path of the flue gases and the sampling points. Results of the analyses of the coal used to fire the utility boiler are listed in Table A-1. Sulfur content of the coal burned during sampling ranged from 1.7% to 2.5%.

AIR SAMPLING PROCEDURE

Particle size data and samples for PCB, POM, and elemental analyses were collected using a Source Assessment Sampling System (SASS) train. This train, depicted in Figure A-2, employs a set of three cyclones for particulate size fractionation, a solid sorbent trap utilizing XAD-2 resin for organic collection, an impinger collection trap for trace inorganics, and a system for flow measurement and gas pumping [113]. The impinger portion of the train consists of four impingers whose order, contents, and purpose are shown in Table A-2 [113]. The sampling and analysis procedures used on this project, as described in Reference 113, have since been modified [114].

Prior to operating the SASS train, a velocity traverse and moisture determination were completed at each sampling location using EPA Method 2 [115] and Method 4 [116]. These methods were employed to determine the point of average velocity and to characterize the source to an extent sufficient for operating the sampling system as close to isokinetic conditions as possible within the available nozzle sizes and operating parameters.

Preparation and operation of the SASS train was conducted as outlined in the IERL-RTP Procedures Manual [113]. In brief, the presampling cleaning included passivation of all sample surfaces

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[113] Hamersama, J. W., S. L. Reynolds, and R. F. Maddalone. IERL-RTP Procedure Manual: Level I Environmental Assessment. EPA-600/2-76-160a (PB 257 850), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, June 1976. 131 pp.

[114] Lentzen, D. E., D. E. Wagoner, E. D. Estes, and W. F. Gutknecht. IERL-RTP Procedures Manual: Level I Environmental Assessment (Second Edition). EPA-600/7-78-201, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, October 1978. 279 pp.

[115] Method 2 - Determination of Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot Tube). Federal Register, 41(111):23063-23069, 1976.

[116] Method 4 - Determination of Moisture in Stack Gases. Federal Register, 41(111):23072-23076, 1976.

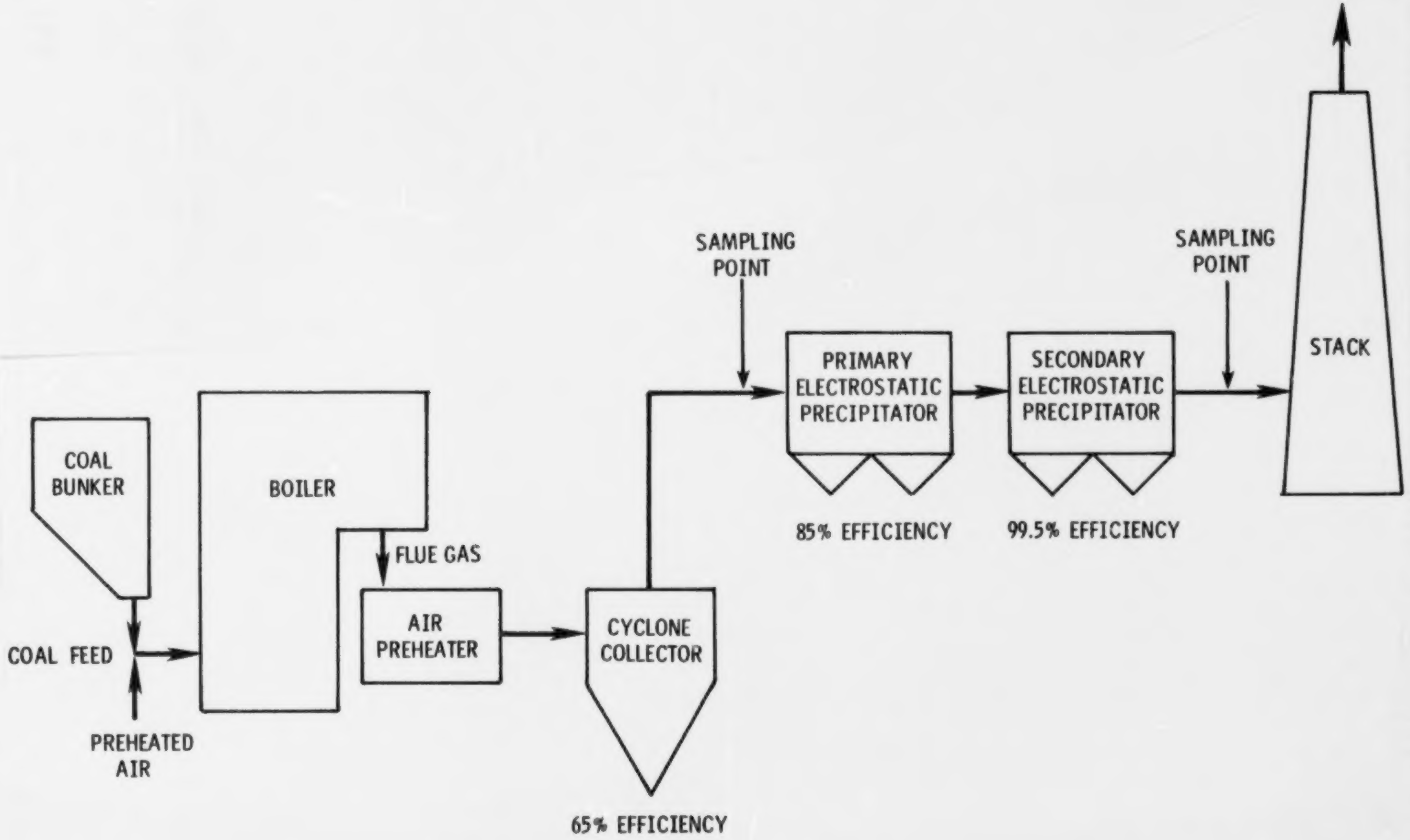
SAMPLING POINT
SAMPLING POINT
STACK
PRIMARY ELECTROSTATIC PRECIPITATOR
SECONDARY ELECTROSTATIC PRECIPITATOR
COAL BUNKER
BOILER
85% EFFICIENCY
99.5% EFFICIENCY
FLUE GAS
AIR PREHEATER
CYCLONE COLLECTOR
COAL FEED
PREHEATED AIR
65% EFFICIENCY

Figure A-1. Schematic of the Utility Boiler System.

TABLE A-1. ANALYSIS OF COAL BURNED AT TEST SITE[a]

Test run number	Heating value, MJ/kg (Btu/lb)	Moisture content, percent	Ash content, percent	Sulfur content, percent	Volatile matter content, percent	Fixed carbon content, percent
MC outlet						
1	28.14 (12,113)	1.62	14.59	2.23	35.39	48.40
2	26.57 (11,439)	1.18	23.11	2.45	33.40	42.31
ESP outlet						
1	26.02 (11,202)	1.17	19.48	1.81	34.35	45.00
2	27.61 (11,886)	1.06	15.89	1.99	35.93	47.12
3	26.58 (11,441)	2.25	17.40	1.72	33.99	46.36

[a] Coal was sampled before the pulverizer.

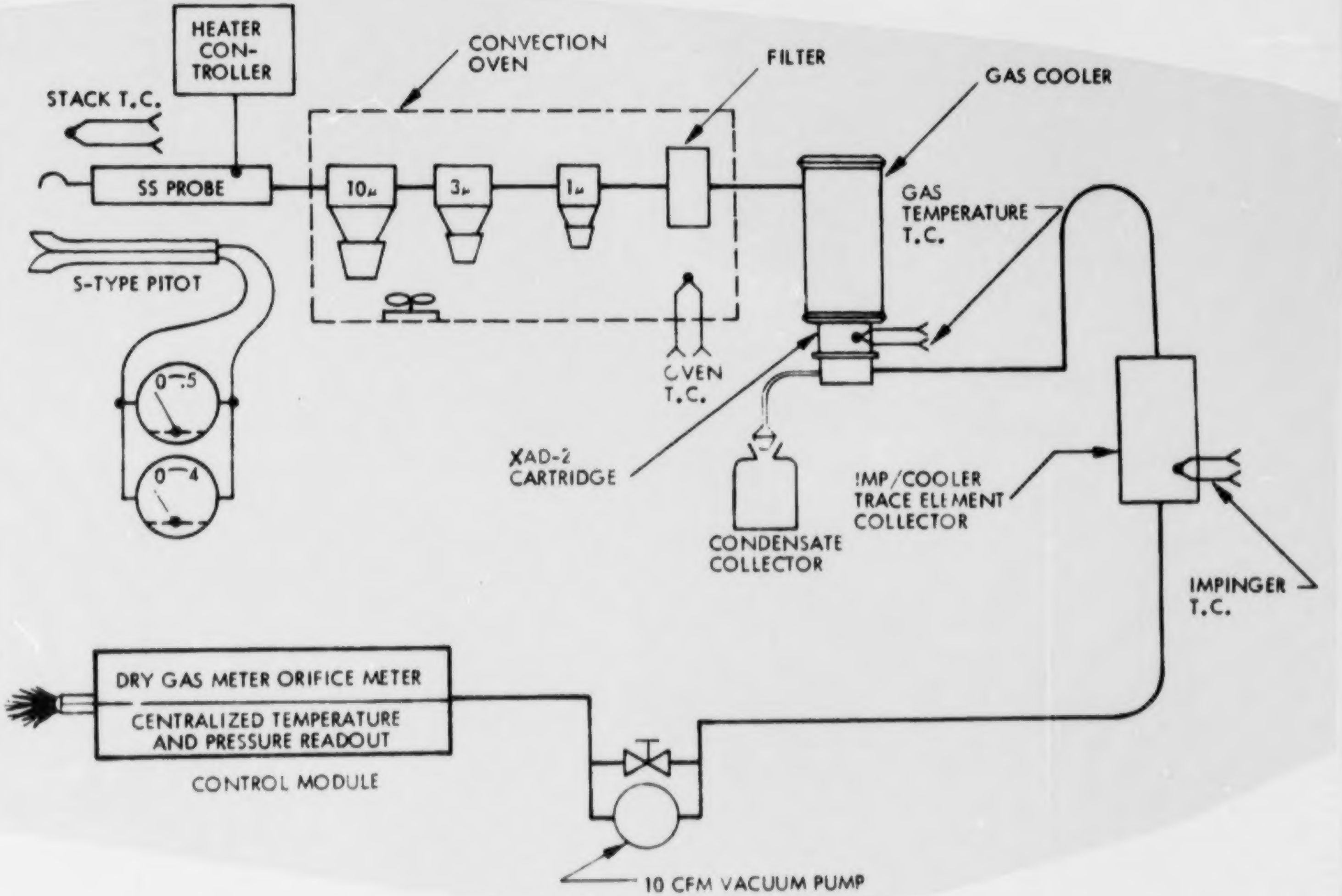
HEATER CON-TROLLER
CONVECTION OVEN
FILTER
GAS COOLER
STACK T.C.
SS PROBE
10μ
3μ
1μ
GAS TEMPERATURE T.C.
S-TYPE PITOT
0–.5
0–4
OVEN T.C.
XAD-2 CARTRIDGE
IMP/COOLER TRACE ELEMENT COLLECTOR
CONDENSATE COLLECTOR
IMPINGER T.C.
DRY GAS METER ORIFICE METER
CENTRALIZED TEMPERATURE AND PRESSURE READOUT
CONTROL MODULE
10 CFM VACUUM PUMP

Figure A-2. Source Assessment Sampling System train [113].

TABLE A-2. SASS TRAIN IMPINGER SYSTEM REAGENTS [113]

Impinger	Reagent	Quantity	Purpose
1	6M H_2O_2	750 ml	Trap reducing gases such as SO_2 to prevent depletion of oxidative capability of trace-element collection impingers 2 and 3.
2	0.2M $(NH_4)_2S_2O_8$ + 0.02M $AgNO_3$	750 ml	Collect volatile trace elements by oxidative dissolution.
3	0.2M $(NH_4)_2S_2O_8$ + 0.02M $AgNO_3$	750 ml	Collect volatile trace elements by oxidative dissolution.
4	Silica gel (3-8 mesh) (color indicating)	750 g	Prevent moisture from reaching pumps.

with aqueous nitric acid (50% by volume). All samples associated with the collection of organics were subsequently cleaned with distilled water, isopropyl alcohol, and methylene chloride, in succession. The impinger portion, used for inorganic collection, was cleaned with distilled water followed by isopropyl alcohol.

At the sampling site, the SASS train was assembled and checked for leaks after heating the oven to 205°C while maintaining the organic resin trap at 20°C. A leak rate of less than 2.36×10^{-5} m^3/s at 67.6 kPa was considered acceptable. After passing the leak check, the probe tip was attached, the impingers were filled, and sampling was begun using a rate of 1.4×10^{-3} to 2.4×10^{-3} m^3/s at the dry test meter. Each SASS train run was conducted for a period in excess of five hours in order to collect approximately 30 m^3. Cleanup procedures used after each run were those specified in the procedures manual [113] and shown graphically in Figures A-3 through A-5.

Sulfur dioxide, sulfur trioxide (acid mist), and particulate sulfate emissions were measured using a procedure based on EPA Method 8 [117]. The Method 8 train was modified to allow collection of particulate sulfate by inserting a filter between the

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[117] Method 8 - Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sources. Federal Register, 41(111):23087-23090, 1976.

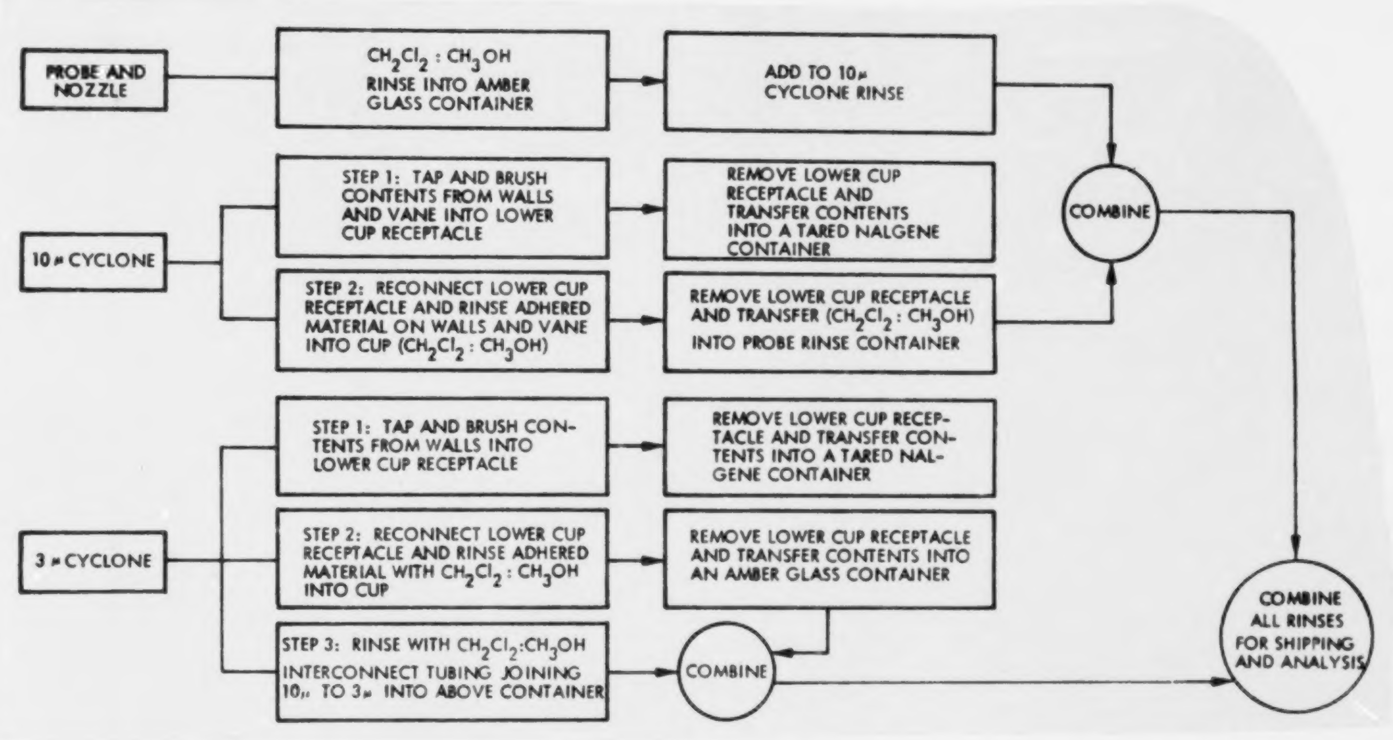
PROBE AND NOZZLE
$CH_2Cl_2 : CH_3OH$ RINSE INTO AMBER GLASS CONTAINER
ADD TO 10μ CYCLONE RINSE
10μ CYCLONE
STEP 1: TAP AND BRUSH CONTENTS FROM WALLS AND VANE INTO LOWER CUP RECEPTACLE
REMOVE LOWER CUP RECEPTACLE AND TRANSFER CONTENTS INTO A TARED NALGENE CONTAINER
STEP 2: RECONNECT LOWER CUP RECEPTACLE AND RINSE ADHERED MATERIAL ON WALLS AND VANE INTO CUP ($CH_2Cl_2 : CH_3OH$)
REMOVE LOWER CUP RECEPTACLE AND TRANSFER ($CH_2Cl_2 : CH_3OH$) INTO PROBE RINSE CONTAINER
COMBINE
3μ CYCLONE
STEP 1: TAP AND BRUSH CONTENTS FROM WALLS INTO LOWER CUP RECEPTACLE
REMOVE LOWER CUP RECEPTACLE AND TRANSFER CONTENTS INTO A TARED NALGENE CONTAINER
STEP 2: RECONNECT LOWER CUP RECEPTACLE AND RINSE ADHERED MATERIAL WITH $CH_2Cl_2 : CH_3OH$ INTO CUP
REMOVE LOWER CUP RECEPTACLE AND TRANSFER CONTENTS INTO AN AMBER GLASS CONTAINER
STEP 3: RINSE WITH $CH_2Cl_2:CH_3OH$ INTERCONNECT TUBING JOINING 10μ TO 3μ INTO ABOVE CONTAINER
COMBINE
COMBINE ALL RINSES FOR SHIPPING AND ANALYSIS

Figure A-3. Sample handling and transfer: nozzle, probe, cyclones, and filter [113].

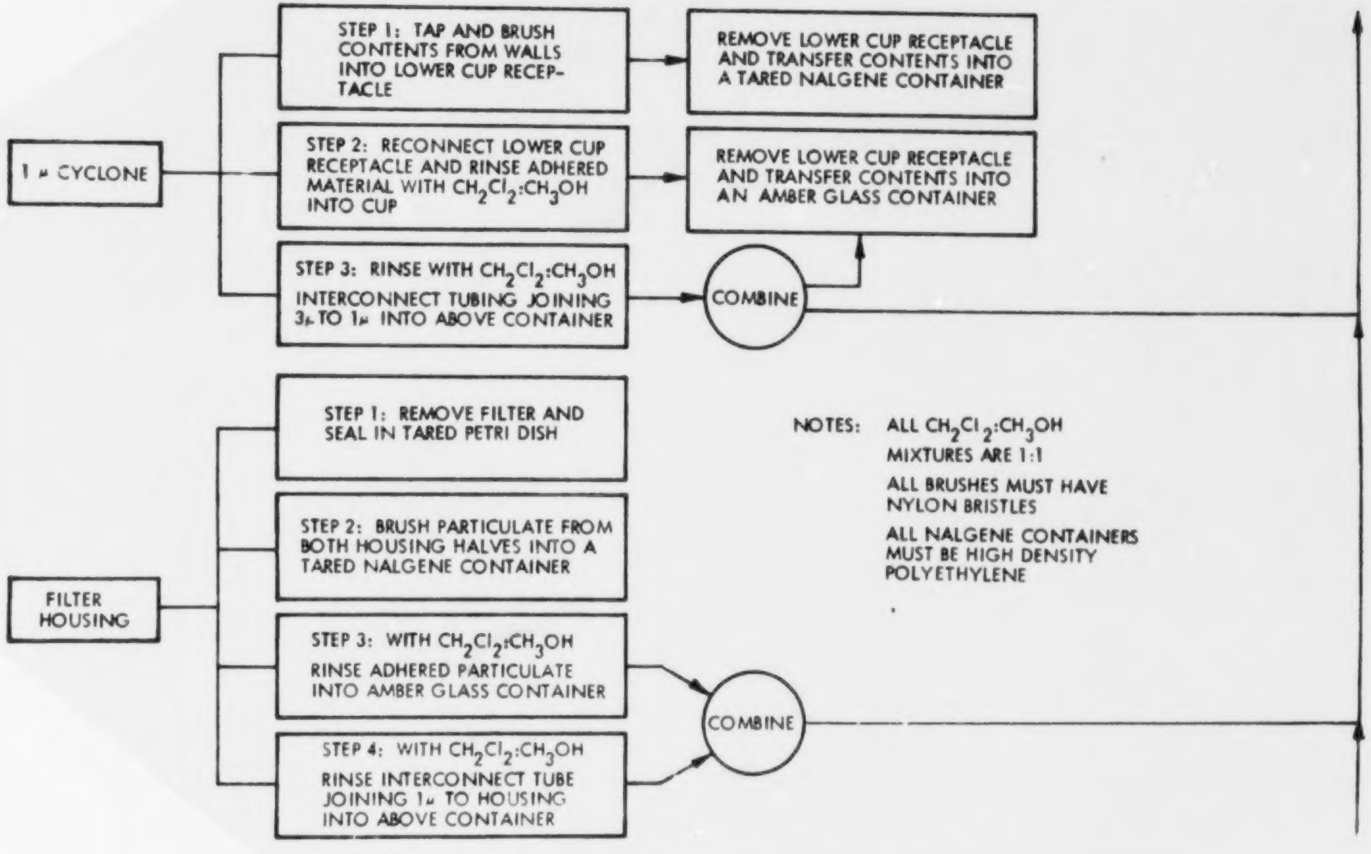
1 µ CYCLONE
STEP 1: TAP AND BRUSH CONTENTS FROM WALLS INTO LOWER CUP RECEPTACLE
STEP 2: RECONNECT LOWER CUP RECEPTACLE AND RINSE ADHERED MATERIAL WITH CH_2Cl_2:CH_3OH INTO CUP
STEP 3: RINSE WITH CH_2Cl_2:CH_3OH INTERCONNECT TUBING JOINING 3µ TO 1µ INTO ABOVE CONTAINER
REMOVE LOWER CUP RECEPTACLE AND TRANSFER CONTENTS INTO A TARED NALGENE CONTAINER
REMOVE LOWER CUP RECEPTACLE AND TRANSFER CONTENTS INTO AN AMBER GLASS CONTAINER
COMBINE
FILTER HOUSING
STEP 1: REMOVE FILTER AND SEAL IN TARED PETRI DISH
STEP 2: BRUSH PARTICULATE FROM BOTH HOUSING HALVES INTO A TARED NALGENE CONTAINER
STEP 3: WITH CH_2Cl_2:CH_3OH RINSE ADHERED PARTICULATE INTO AMBER GLASS CONTAINER
STEP 4: WITH CH_2Cl_2:CH_3OH RINSE INTERCONNECT TUBE JOINING 1µ TO HOUSING INTO ABOVE CONTAINER
COMBINE
NOTES: ALL CH_2Cl_2:CH_3OH MIXTURES ARE 1:1
ALL BRUSHES MUST HAVE NYLON BRISTLES
ALL NALGENE CONTAINERS MUST BE HIGH DENSITY POLYETHYLENE

Figure A-3 (continued) [113].

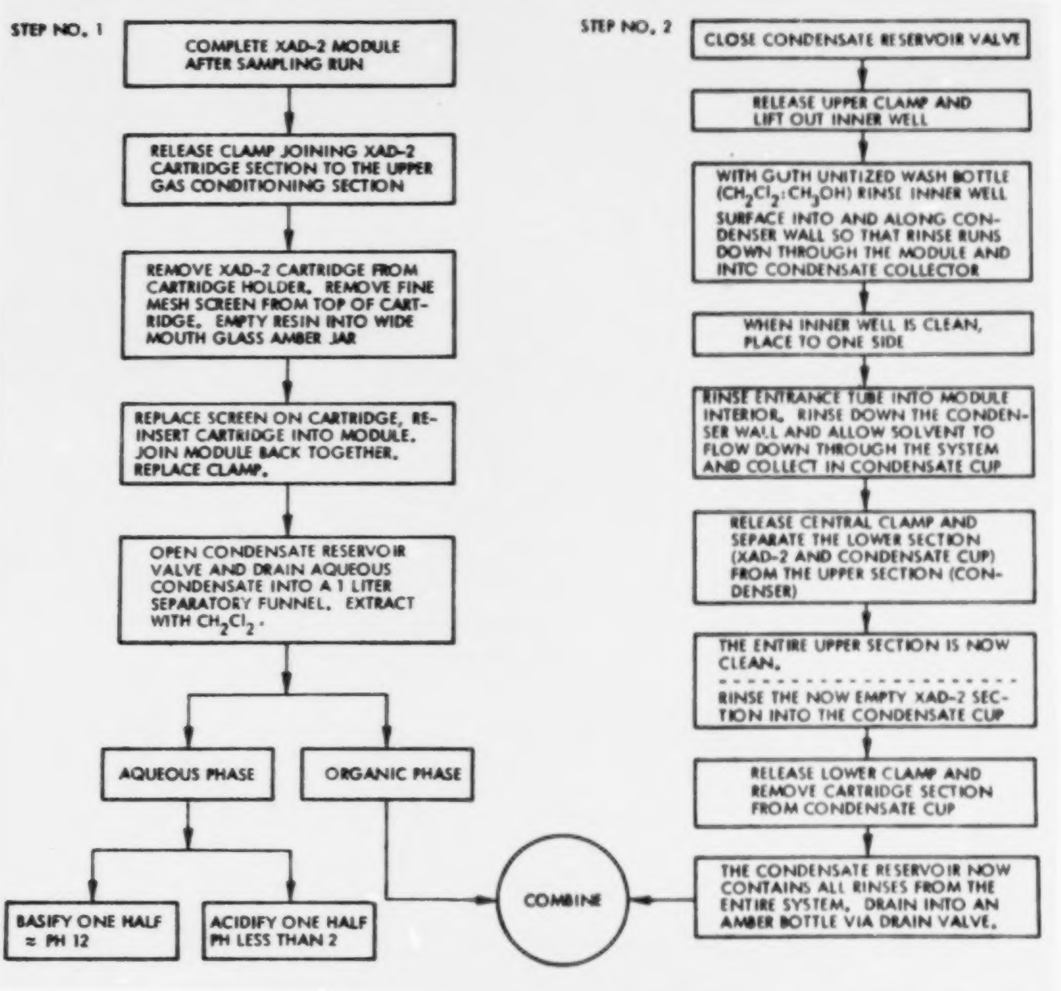
STEP NO. 1
COMPLETE XAD-2 MODULE AFTER SAMPLING RUN
RELEASE CLAMP JOINING XAD-2 CARTRIDGE SECTION TO THE UPPER GAS CONDITIONING SECTION
REMOVE XAD-2 CARTRIDGE FROM CARTRIDGE HOLDER. REMOVE FINE MESH SCREEN FROM TOP OF CARTRIDGE. EMPTY RESIN INTO WIDE MOUTH GLASS AMBER JAR
REPLACE SCREEN ON CARTRIDGE, REINSERT CARTRIDGE INTO MODULE. JOIN MODULE BACK TOGETHER. REPLACE CLAMP.
OPEN CONDENSATE RESERVOIR VALVE AND DRAIN AQUEOUS CONDENSATE INTO A 1 LITER SEPARATORY FUNNEL. EXTRACT WITH CH_2Cl_2.
AQUEOUS PHASE
ORGANIC PHASE
BASIFY ONE HALF ≈ PH 12
ACIDIFY ONE HALF PH LESS THAN 2
COMBINE
STEP NO. 2
CLOSE CONDENSATE RESERVOIR VALVE
RELEASE UPPER CLAMP AND LIFT OUT INNER WELL
WITH GUTH UNITIZED WASH BOTTLE ($CH_2Cl_2:CH_3OH$) RINSE INNER WELL SURFACE INTO AND ALONG CONDENSER WALL SO THAT RINSE RUNS DOWN THROUGH THE MODULE AND INTO CONDENSATE COLLECTOR
WHEN INNER WELL IS CLEAN, PLACE TO ONE SIDE
RINSE ENTRANCE TUBE INTO MODULE INTERIOR. RINSE DOWN THE CONDENSER WALL AND ALLOW SOLVENT TO FLOW DOWN THROUGH THE SYSTEM AND COLLECT IN CONDENSATE CUP
RELEASE CENTRAL CLAMP AND SEPARATE THE LOWER SECTION (XAD-2 AND CONDENSATE CUP) FROM THE UPPER SECTION (CONDENSER)
THE ENTIRE UPPER SECTION IS NOW CLEAN.
RINSE THE NOW EMPTY XAD-2 SECTION INTO THE CONDENSATE CUP
RELEASE LOWER CLAMP AND REMOVE CARTRIDGE SECTION FROM CONDENSATE CUP
THE CONDENSATE RESERVOIR NOW CONTAINS ALL RINSES FROM THE ENTIRE SYSTEM. DRAIN INTO AN AMBER BOTTLE VIA DRAIN VALVE.

Figure A-4. Sampling handling and transfer: XAD-2 module [113].

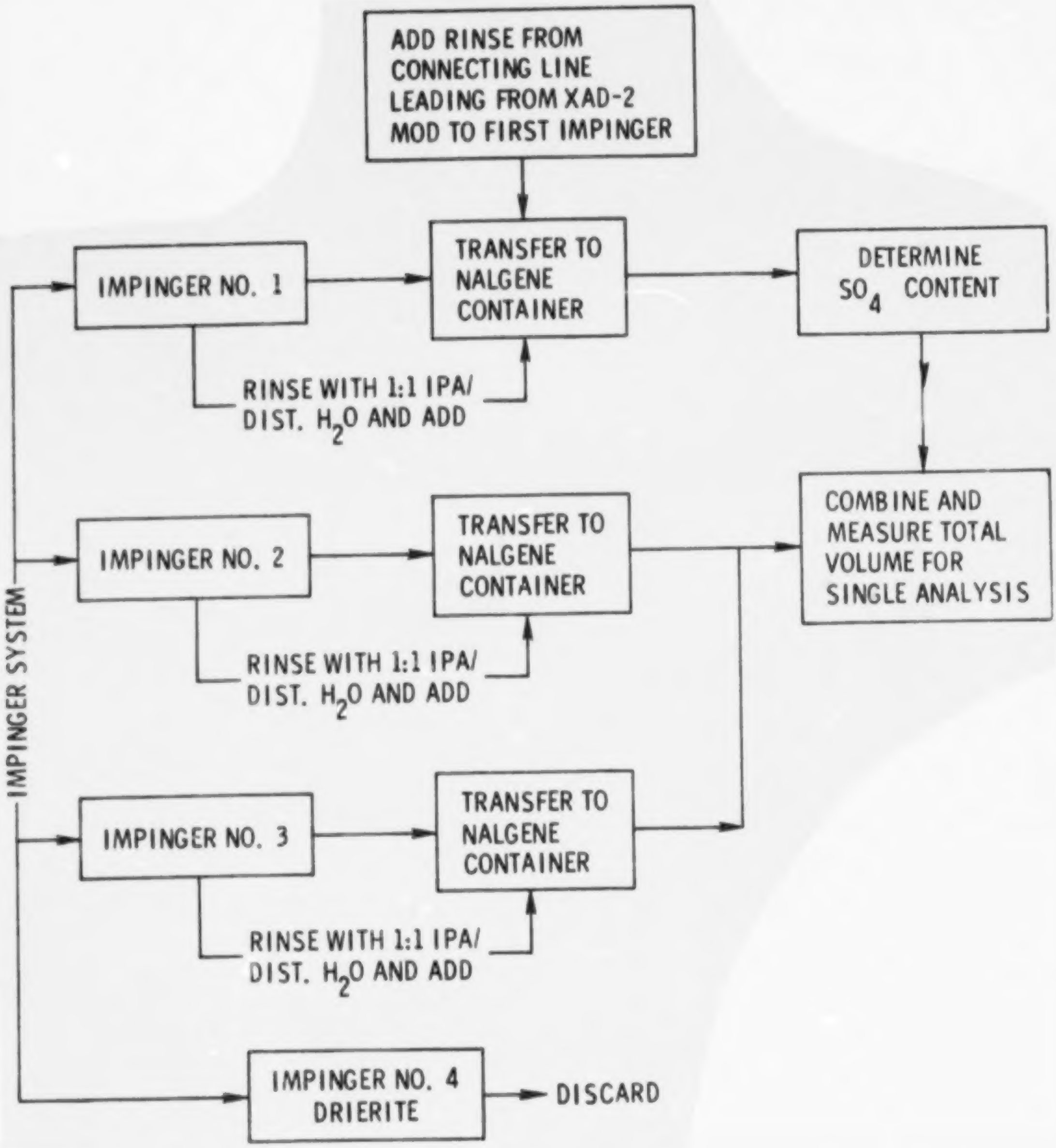
ADD RINSE FROM CONNECTING LINE LEADING FROM XAD-2 MOD TO FIRST IMPINGER
IMPINGER NO. 1
TRANSFER TO NALGENE CONTAINER
DETERMINE SO_4 CONTENT
RINSE WITH 1:1 IPA/ DIST. H_2O AND ADD
IMPINGER NO. 2
TRANSFER TO NALGENE CONTAINER
COMBINE AND MEASURE TOTAL VOLUME FOR SINGLE ANALYSIS
RINSE WITH 1:1 IPA/ DIST. H_2O AND ADD
IMPINGER SYSTEM
IMPINGER NO. 3
TRANSFER TO NALGENE CONTAINER
RINSE WITH 1:1 IPA/ DIST. H_2O AND ADD
IMPINGER NO. 4 DRIERITE
DISCARD

Figure A-5. Sample handling and transfer: impingers [113].

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7403

probe and the first impinger and maintaining it at a temperature ($\sim$150°C) sufficient to volatilize sulfuric acid mist. (The observed low particulate sulfate values, as shown later in Table A-4, confirm that SO_3 did not absorb onto the particulate material on the filter.) Sampling was then conducted at isokinetic conditions with traversing. At the conclusion of each run, the filter was placed in a petri dish and sealed. The probe and front half of the filter holder were washed with distilled water which was then bottled. Post-sampling treatment of the rest of the train and samples followed the normal procedures in Method 8.

Low-molecular-weight hydrocarbons (C_1 to C_6) were sampled by collecting integrated gas samples in Tedlar bags. The bag contents were then analyzed within 24 hours using gas chromatography. Integrated gas samples were also collected for carbon dioxide, excess air, and dry molecular weight determinations using EPA Method 3 [118].

ANALYTICAL PROCEDURES

Field samples which required laboratory analysis include those from the SASS train for particle sizing, organic analysis (hydrocarbons greater than C_7, POM, and PCB), and trace element analysis; and the mofidied EPA Method 8 train for sulfur dioxide, sulfur trioxide, and particulate sulfate. Trace elements were analyzed by inductively coupled argon plasma emission spectroscopy (ICAP) and atomic absorption (AA) rather than spark source mass spectroscopy (SSMS) because it was determined that these two techniques would measure all elements which have controlled ambient severities ≥ 0.05. The species not measured by ICAP and AA were determined to possess controlled ambient severities of less than 0.05.

SASS Train Samples

The separation and analysis of the SASS train samples is depicted in Figure A-6 and, in general, follows the methods employed for Level I type analysis. These methods are briefly outlined below. The procedures described here have since been modified, as noted in Reference 114.

Cyclone Collected Material--

Cyclone materials were weighed separately to provide particulate size data. After weighing, the cyclone contents were combined into one sample and extracted for 24 hours with methylene chloride because of the small sample size. This is a deviation from the Level I procedure in which a portion is removed prior to

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[118] Method 3 - Gas Analysis for Carbon Dioxide, Oxygen, Excess Air, and Dry Molecular Weight. Federal Register, 41(111): 23069-23070, 1976.

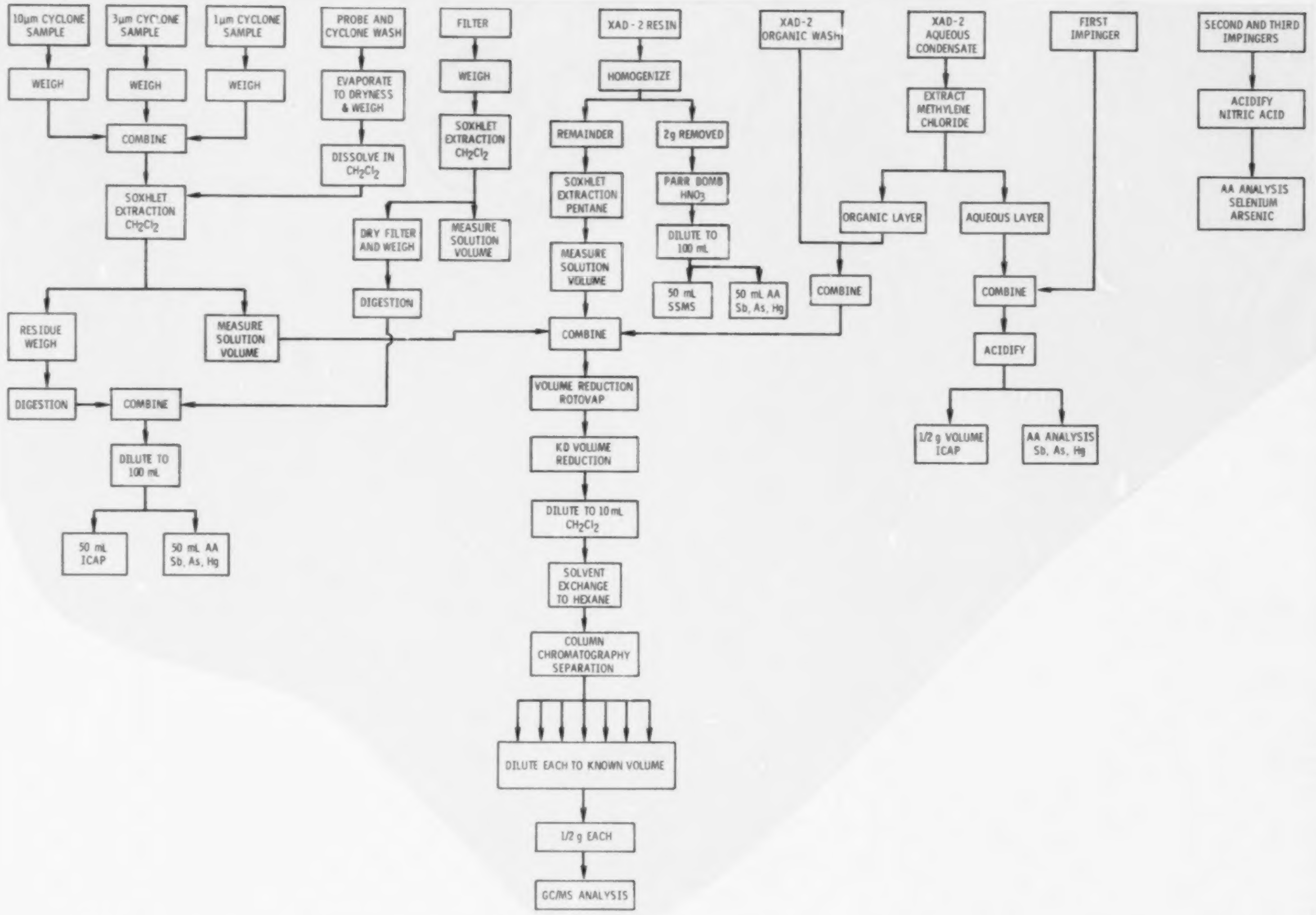
10μm CYCLONE SAMPLE
3μm CYCLONE SAMPLE
1μm CYCLONE SAMPLE
PROBE AND CYCLONE WASH
FILTER
XAD - 2 RESIN
XAD-2 ORGANIC WASH
XAD-2 AQUEOUS CONDENSATE
FIRST IMPINGER
SECOND AND THIRD IMPINGERS
WEIGH
WEIGH
WEIGH
EVAPORATE TO DRYNESS & WEIGH
WEIGH
HOMOGENIZE
EXTRACT METHYLENE CHLORIDE
ACIDIFY NITRIC ACID
COMBINE
DISSOLVE IN CH_2Cl_2
SOXHLET EXTRACTION CH_2Cl_2
REMAINDER
2g REMOVED
SOXHLET EXTRACTION CH_2Cl_2
SOXHLET EXTRACTION PENTANE
PARR BOMB HNO_3
ORGANIC LAYER
AQUEOUS LAYER
AA ANALYSIS SELENIUM ARSENIC
DRY FILTER AND WEIGH
MEASURE SOLUTION VOLUME
MEASURE SOLUTION VOLUME
DILUTE TO 100 mL
50 mL SSMS
50 mL AA Sb, As, Hg
COMBINE
COMBINE
DIGESTION
RESIDUE WEIGH
MEASURE SOLUTION VOLUME
COMBINE
ACIDIFY
DIGESTION
COMBINE
VOLUME REDUCTION ROTOVAP
1/2 g VOLUME ICAP
AA ANALYSIS Sb, As, Hg
KD VOLUME REDUCTION
DILUTE TO 100 mL
DILUTE TO 10 mL CH_2Cl_2
50 mL ICAP
50 mL AA Sb, As, Hg
SOLVENT EXCHANGE TO HEXANE
COLUMN CHROMATOGRAPHY SEPARATION
DILUTE EACH TO KNOWN VOLUME
1/2 g EACH
GC/MS ANALYSIS

Figure A-6. Separation and analysis scheme: SASS train samples [113].

extraction for trace element analysis. After extraction, the residue (unextractables) in the thimble was reweighed and then digested for trace element analysis by ICAP and AA. For this type sample, the solid was digested in a HNO_3-perchloric acid medium because fly ash is difficult to digest using the normal Parr bomb technique. The volume of the liquid from the Soxhlet extraction was measured and the liquid was combined with the extracted portions of the filter.

Probe and Cyclone Washes--
The methylene chloride-methanol washings of the probe, cyclones, and filter holder were evaporated to dryness and weighed. The dry material was then dissolved in methylene chloride and transferred quantitatively to the Soxhlet extraction apparatus along with the cyclone collected material.

Filter--
The filter from the SASS train was dried and weighed, and the weight was combined with the cyclone collection and washing from the "front" portion of the train. The filter was then Soxhlet extracted for 24 hours with methylene chloride. The filter was dried and weighed, and the volume of the extraction solution was measured. This solution was combined with the cyclone extraction solution, the XAD-2 resin extract, and the organic washing of the XAD-2 resin trap. The filter and nonextractable residue were digested using Parr bomb and HNO_3-perchloric acid digestion. The resulting solution was separated from the filter remains and combined with the solution from the cyclone material digestion.

XAD-2 Resin--
The resin was stirred to mix the sample thoroughly, and a 2-gram portion was removed and digested in the Parr bomb with nitric acid. Digested materials were diluted to a known volume and divided for the various trace element analyses. Remaining XAD-2 resin (about 250 grams) was Soxhlet extracted for 24 hours with pentane. The resulting solution was combined with the methylene chloride extraction material from the cyclones and filters, and the organic wash from the resin trap.

First Impinger Contents, XAD-2 Trap
Organic Wash, and Aqueous Condensate--
Aqueous condensate from the resin trap was extracted with methylene chloride, and the organic portion was combined with the methylene chloride wash of the trap. The resulting solution was combined with the XAD-2 resin, filter, and particulate extracts prior to volume reduction and liquid chromatography fractionation. Remaining aqueous layers were combined with the liquid from the first impinger, and the solution was acidified and divided for trace element analysis.

Second and Third Impingers--

Contents of the second and third impingers were acidified and analyzed using atomic absorption for mercury, arsenic, and selenium.

Sulfur Oxides, Sulfuric Acid and Particulate Sulfate

Samples for sulfur analysis, collected by the modified Method 8 sampling system, consisted of the particulate filter, the first impinger (isopropanol), the filter between the impingers, and the second and third impingers (hydrogen peroxide). Procedures described in Method 8 were employed for the analysis of the impingers and the filter between impingers; that is, titration with barium perchlorate using Thorin indicator [117]. Analysis of the particulate filter required digestion of the material on the filter using a combination of nitric and perchloric acids in order to oxidize and dissolve the fly ash. Following digestion, the sample was analyzed for sulfate content using a gravimetric procedure involving barium nitrate to precipitate the sulfate as barium sulfate.

Coal Samples

Three samples of the coal feed were analyzed for moisture content, ash, heating value, carbon-hydrogen-nitrogen content, sulfur, and sulfate. These analyses were conducted employing ASTM standard methods [119, 120].

Trace Organic Analysis

Trace organic analysis was conducted on the organic components from the SASS collection, which were contained in the pentane extractions of the cyclone and filter catch, the pentane extract of the XAD-2 resin trap, and in the solid residue from the probe washes. The residue from the probe wash was dissolved in 2.5×10^{-5} m^3 (25 ml) of pentane.

Following volume reduction, the samples were separated into eight fractions, using the solvent systems shown in Figure A-7, on a silica gel column. Each fraction was then reduced in volume

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[119] Standard Method of Test for Proximate Analysis of Coal and Coke, Designation D 3172-73. In: 1973 Annual Book of ASTM Standards, Part 19: Gaseous Fuels; Coal and Coke. American Society for Testing and Materials, Philadelphia, Pennsylvania, 1973. p. 434.

[120] Standard Method of Test for Forms of Sulfur in Coal, Designation D 2492-68. In: 1973 Annual Book of ASTM Standards, Part 19: Gaseous Fuels; Coal and Coke. American Society for Testing and Materials, Philadelphia, Pennsylvania, 1973. pp. 380-384.

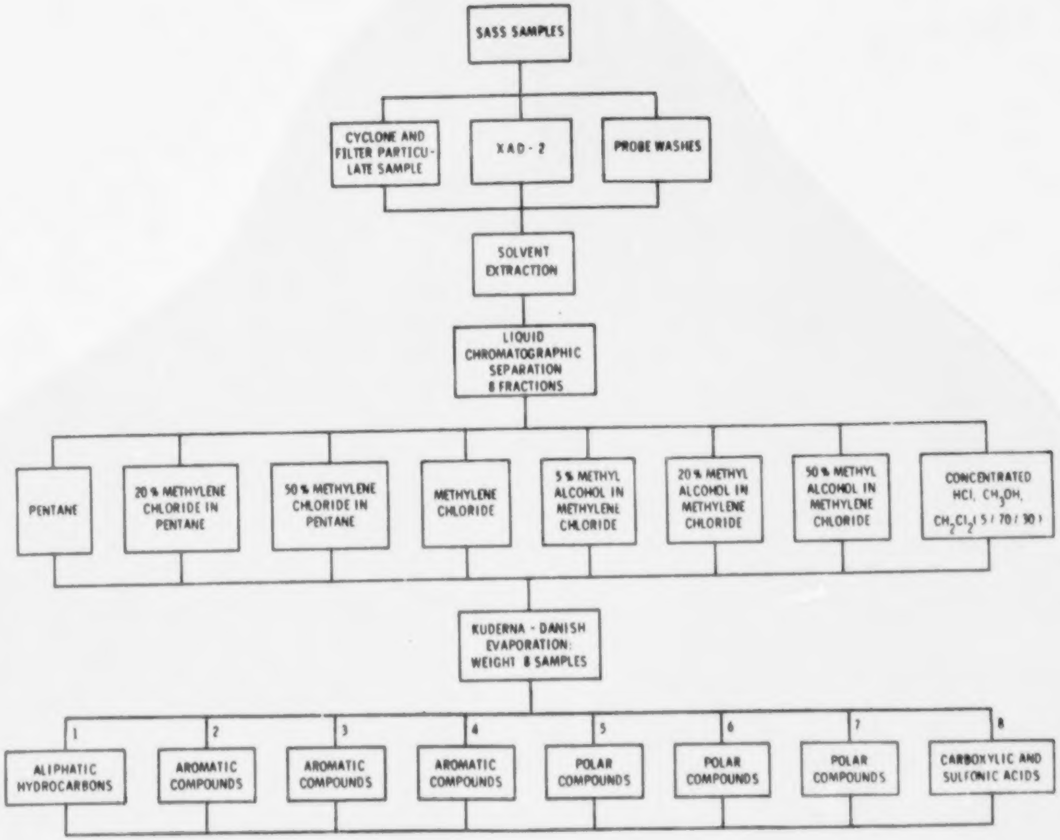
SASS SAMPLES
CYCLONE AND FILTER PARTICULATE SAMPLE
XAD-2
PROBE WASHES
SOLVENT EXTRACTION
LIQUID CHROMATOGRAPHIC SEPARATION 8 FRACTIONS
PENTANE
20 % METHYLENE CHLORIDE IN PENTANE
50 % METHYLENE CHLORIDE IN PENTANE
METHYLENE CHLORIDE
5 % METHYL ALCOHOL IN METHYLENE CHLORIDE
20 % METHYL ALCOHOL IN METHYLENE CHLORIDE
50 % METHYL ALCOHOL IN METHYLENE CHLORIDE
CONCENTRATED HCl, CH3OH, CH2Cl2 (5/70/30)
KUDERNA - DANISH EVAPORATION: WEIGHT 8 SAMPLES
1
ALIPHATIC HYDROCARBONS
2
AROMATIC COMPOUNDS
3
AROMATIC COMPOUNDS
4
AROMATIC COMPOUNDS
5
POLAR COMPOUNDS
6
POLAR COMPOUNDS
7
POLAR COMPOUNDS
8
CARBOXYLIC AND SULFONIC ACIDS

Figure A-7. Analysis flow diagram.

using a Kuderna-Danish evaporator and transferred to a tare-weighted, micro-weighing pan; the remaining solvent was evaporated in air. Each dried fraction was weighed and then redissolved in a minimum quantity of methylene chloride.

The second, third, and fourth fractions (containing the POM and PCB components) were combined and transferred to a Viton-septum sealed vial which was covered with aluminum foil and refrigerated until required for analysis. Just prior to analysis, the sample underwent one more volume reduction via the Kuderna-Danish method. The final volume was approximately 5 x 10^{-7} m^3 (500 μl). This volume size has been found to be optimum for detecting the POM peaks without their being obscured by the contamination peaks.

POM Analysis Procedure--

The method used for POM analysis employs a peak-area quantitation technique with computer reconstructed chromatograms from the (HP 5982-A) gas chromatograph - mass spectrograph (GC-MS). All data were collected in the electron impact (EI) mode because of the abundance of available EI-mass spectra.

The gas chromatographic separation was achieved using a 1.8-m Dexsil 400 glass column with temperature programming from 160°C for 2 min, rising to 280°C at 8°C/min, and becoming isothermal at 280°C. Helium, at a flow rate of 0.5 x 10^{-9} m/s (30 μl/min), was used as carrier gas.

The mass spectrometer, operating in the electron impact mode, was programmed to scan the 75-350 AMU range as the POM components eluted from the gas chromatograph. The data system reconstructed the chromatogram using the total ion mode. POM's were located by their molecular mass ions which are displayed using the selected ion mode (SIM). Their identity was confirmed by examination of their mass spectra and retention times.

Calibration curves were prepared for each POM of interest using varying concentrations of the POM standards in methylene chloride, plotting mass ion peak area *vs* concentration, and determining response factors. POM peaks in samples were compared with standard curves that have been obtained under the same conditions, attenuation, injection volume (2 x 10^{-9} m^3 or 2 μl), and tuning condition. Calibrations were made on the same day that the samples were analyzed.

PCB Analysis Procedure--

The GC-MS technique was used for the analysis of PCB compounds. Concentrated solutions from the second, third, and fourth fractions from the silica gel separations were examined. Samples were injected into the GC and separated on a 3% Dexsil 400 column operated isothermally at 250°C for SIM or 280°C for EIM. Mass spectra were obtained in the electron impact mode because the fragmentations of a number of isomeric mono-, di-, tri-, tetra-, bena-, octa-, and decachloro-biphenyl has been studied in detail using this procedure. Quantification of the data was performed using standards of the various chlorinated biphenyls in methylene chloride.

Trace Element Analysis

The Jarrell-Ash Plasma Atomcomp (ICAP) and atomic absorption methods were used for trace element analysis of the collected samples.

Jarrell-Ash Plasma Atomcomp Analysis--

The Jarrell-Ash Plasma Atomcomp technique was used at the Physical Science Center of Monsanto Company in St. Louis for the analysis of aluminum, antimony, barium, boron, cadmium, calcium, chromium, cobalt, copper, iron, lead, magnesium, manganese, molybdenum, nickel, phosphorus, silicon, silver, sodium, strontium, tin, titanium, vanadium, and zinc. The Atomcomp employs an inductively coupled argon plasma (ICAP) as an excitation source to produce atomic emission which is relatively free of interferences.

Atomic Absorption Analysis--

Atomic absorption was employed to analyze for mercury, arsenic, and selenium. Mercury was analyzed using the cold vapor technique in which all of the mercury is reduced to the metallic state with $SnCl_2$ and then swept into the quartz cuvette for AA analysis [121]. Arsenic, selenium, and antimony were analyzed via the hydride generation technique developed and refined by Fernandez [122] and more recently by Brodie [123]. An aqueous solution was first reacted with a reducing agent (e.g., potassium iodide), then the corresponding gaseous hydride was generated with sodium borohydride which was immediately swept into a nitrogen-hydrogen entrained-air flame for analysis.

RESULTS

Particulate Emissions

Particulate mass emission rates were determined using the modified EPA Method 8 procedure and the SASS train. Table A-3 shows that the ESP effected a 97% reduction in particulate emissions.

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[121] Parker, C. R. Water Analysis by Atomic Absorption. Varian Techtron Pty., Ltd., Springvale, Victoria, Australia, Reprint 1976. 78 pp.

[122] Fernandez, F. G. Atomic Absorption Determination of Gaseous Hydrides Utilizing Sodium Borohydride Reduction. Atomic Absorption Newsletter, 12(4):93-97, 1973.

[123] Brodie, k. G. Determining Arsenic and Selenium by AAS. American Laboratory, 9(3):73-79, 1977.

TABLE A-3. PARTICULATE EMISSION FACTORS (g/kg)

Sampling method	Uncontrolled emissions	Controlled emissions
Method 8	26	1.3
	15	0.27
	31	0.47
SASS train	47	0.069

Sulfur Compounds and Particulate Sulfate

Sulfur, sulfur dioxide, sulfur trioxide (acid mist), and particulate sulfate emissions were measured using a procedure based on EPA Method 8. Emissions factors are shown in Table A-4 for each run made. The average emissions factors at the ESP inlet for total sulfur, sulfur dioxide, sulfur trioxide and particulate sulfate were determined to be 15.05 g/kg, 35.5 g/kg, 0.395 g/kg, and <0.06 g/kg, respectively. At the outlet of the ESP, average emission factors did not change by a significant amount except in the case of the particulate sulfate.

Low Molecular Weight Hydrocarbons

Analysis of gas samples revealed emission factors below the detection limit of 1 ppm in most cases. Results are given in Table A-5.

POM and PCB Emissions

Samples for POM and PCB analyses were collected using the SASS train. This train employs a set of three cyclones for particulate size fractionation, a solid sorbent trap utilizing XAD-2 resins for organic collection, and an impinger collection trap for trace inorganics. The method employed for POM and PCB analysis was GC/MS. Emission factors are shown in Table A-6.

Elemental Emissions

Samples for elemental analysis were collected using the SASS train. The Jarrell-Ash Plasma Atomcomp (ICAP) and atomic absorption methods were used for trace element analysis of the collected samples. Results are given in Table A-7.

TABLE A-4. EMISSIONS OF SO_2, SO_3, AND PARTICULATE SULFATE

Sampling location and test number	Coal sulfur content, %	Emission factors, g/kg of coal feed: Particulate sulfate as SO_4	Emission factors, g/kg of coal feed: Sulfur trioxide and sulfuric acid mist as SO_3	Emission factors, g/kg of coal feed: sulfur dioxide as SO_2	AP-42 SO_x emission factor, g/kg	Percent agreement of measured values with AP-42	Fraction of SO_x as SO_3, %
Mechanical collector outlet							
Run No. 1							
Field analysis	2.23	-[a]	0.30	49.8	42.4	119	0.6
Lab analysis		<0.057	0.48	23.0	42.4	55	2.0
Continuous analyzer		-[a]	-[a]	44.5	42.4	106	-[a]
Run No. 2							
Field Analysis	2.45	-[a]	0.17	52.4	46.6	112	0.33
Lab analysis		<0.059	0.31	48.0	46.6	104	0.64
ESP outlet							
Run No. 1							
Lab analysis	1.81	0.0006	0.26	31.8	34.4	94	0.81
Continuous analyzer		-[a]	-[a]	39.2	34.4	113	-[a]
Run No. 2							
Lab analysis	1.99	<0.0002	0.26	34.7	37.8	93	0.74
Continuous analyzer		-[a]	-[a]	40.2	37.8	106	-[a]
Run No. 3							
Lab analysis	1.72	0.001	0.22	33.1	32.7	102	0.66
Continuous analyzer		-[a]	-[a]	43.1	32.7	131	-[a]

[a] No data available.

TABLE A-5. LOW MOLECULAR WEIGHT HYDROCARBONS EMISSION FACTORS (g/kg)

Run number	Uncontrolled (at mechanical collector outlet)	Controlled (at ESP outlet)
1	<0.015	0.026
2	<0.015	
3	<0.015	<0.015
4	0.027	<0.015
5		0.020
6	<0.015	<0.015

Note: Blanks indicate no sample collected.

TABLE A-6. POM EMISSION FACTORS OBTAINED DURING MRC TEST PROGRAM (μg/kg)

POM species	Uncontrolled (at mechanical collector outlet)	Controlled (at ESP outlet)
Dibenzothiophene	<0.06	0.07
Anthracene/phenanthrene	0.12	1.8
Methylanthracenes/phenanthrenes	1.9	9.0
Dimethylanthracenes/phenanthrenes	8.2	10.8
Fluoranthene	0.60	0.52
Pyrene	1.1	1.0
Methylfluoranthenes/pyrenes	2.9	1.6
Benz(c)phenanthrene[a]	0.18	0.15
Chrysene/benz(a)anthracene[a]	0.60	0.37
Dimethylbenz(a)anthracenes[a]	1.7	1.8
Benzofluoranthenes[a]	<0.06	<0.07
Benzopyrenes (and perylene)[a]	0.30	0.22
Methylchloranthrenes[a]	<0.3	<0.4
Indeno(1,2,3-c,d)pyrene[a]	<0.06	<0.07
Dibenz(a,h)anthracene[a,b]	<0.06	<0.07
Dibenz(c,g)carbazole[a]	<0.3	<0.4
Dibenzopyrenes[a]	1.8	<0.37
Methylchrysenes[a,b]	1.6	1.6
Anthanthrene/benzo(ghi)perylene	<0.03	<0.07
Total	21	29

[a] Known or suspected carcinogens.

[b] May include isomers.

TABLE A-7. ELEMENTAL EMISSION FACTORS OBTAINED DURING MRC TEST PROGRAM
(g/kg)

Element	Uncontrolled (at mechanical collector outlet)	Controlled (at ESP outlet)
Aluminum	<5.5	2.5×10^{-3}
Antimony	2.5×10^{-2}	1.0×10^{-3}
Arsenic	4.2×10^{-2}	2.3×10^{-4}
Barium	$<7.5 \times 10^{-2}$	1.2×10^{-5}
Boron	2.7×10^{-2}	1.8×10^{-2}
Cadmium	1.9×10^{-2}	8.3×10^{-5}
Calcium	<0.59	2.0×10^{-3}
Chromium	5.1×10^{-2}	2.7×10^{-2}
Cobalt	9.2×10^{-3}	6.3×10^{-4}
Copper	0.13	6.4×10^{-4}
Iron	2.2	9.6×10^{-2}
Lead	2.8×10^{-2}	6.0×10^{-4}
Magnesium	3.2×10^{-1}	5.9×10^{-4}
Manganese	1.2×10^{-2}	2.7×10^{-3}
Mercury	7.1×10^{-5}	2.1×10^{-5}
Molybdenum	1.4×10^{-2}	2.0×10^{-3}
Nickel	2.9×10^{-2}	1.4×10^{-2}
Phosphorus	2.5×10^{-1}	1.2×10^{-3}
Selenium	8.9×10^{-4}	1.3×10^{-4}
Silicon	8.7×10^{-3}	1.7×10^{-2}
Silver	$<2.1 \times 10^{-2}$	0
Sodium	2.1×10^{-1}	1.2×10^{-2}
Strontium	3.8×10^{-2}	1.9×10^{-5}
Tin	$<3.1 \times 10^{-2}$	1.8×10^{-4}
Titanium	3.9×10^{-1}	1.1×10^{-4}
Vanadium	8.7×10^{-2}	1.2×10^{-4}
Zinc	$<3.5 \times 10^{-2}$	6.4×10^{-4}

[a] Samples were taken with the SASS train.

APPENDIX B

TABULATION OF SOURCE TEST DATA FROM NEDS

A number of utility boilers in the NEDS listing [6] provide emissions data for criteria pollutants based on source test measurements. Data are reported as total annual emissions (tons/yr) so that emission factors must be calculated by dividing by the annual coal consumption. Tables B-1, B-2, B-3, B-4, and B-5 give data for particulate, SO_x, NO_x, CO, and hydrocarbon emissions, respectively.

TABLE B-1. PARTICULATE EMISSIONS DATA FOR UTILITY BOILERS BURNING PULVERIZED BITUMINOUS COAL (DRY BOTTOM)

Plant code	Particulate emissions, tons/yr	Particulate control efficiency, percent	Coal consumption, tons/yr	Controlled particulate emission factor, g/kg	Uncontrolled particulate emission factor, g/kg	Coal ash content, percent	Uncontrolled emission factor divided by ash content[a]
316	2,860	99.5	270,000	10.6	2,120	13.0	163[b]
317	2,860	99.5	270,000	10.6	2,120	13.0	163[b]
462	227	98.5	335,000	0.678	45.2	8.0	5.65
463	227	98.5	335,000	0.678	45.2	8.0	5.65
473	182	99.8	486,000	0.374	187	22.6	8.27
474	182	99.8	486,000	0.374	187	22.6	8.27
475	234	99.8	626,000	0.374	187	22.6	8.27
476	20,600	98.0	626,000	32.9	1,650	22.6	73.0[b]
590	2,320	85.0	120,000	19.3	129	13.0	9.92
591	2,320	85.0	120,000	19.3	129	10.0	12.9
592	3,160	85.0	178,000	17.8	118	13.0	9.08
593	3,560	85.0	196,000	18.2	121	13.0	9.31
650	777	98.0	299,000	2.60	130	13.9	9.35
651	1,850	97.0	578,000	3.20	107	13.9	7.70
652	801	99.5	1,590,000	0.504	101	13.9	7.27
672	49	79.0	10,000	4.90	23.3	15.0	1.55
673	55	0	6,000	$-^{c}$	9.17	15.0	0.611[b]
674	187	0	19,000	$-^{c}$	9.84	15.0	0.656[b]
675	54	97.5	62,000	0.871	34.8	15.0	2.32
683	14	99.8	29,900	0.468	234	12.7	18.4
684	5	99.9	52,500	0.0952	95.2	12.7	7.50
685	33	99.9	151,000	0.219	219	12.7	17.2
686	71	99.6	106,000	0.670	167	12.7	13.1
687	18	99.8	136,000	0.132	66.2	12.7	5.21
688	12	99.9	77,200	0.155	155	12.7	12.2
705	534	0	79,700	$-^{c}$	6.70	12.6	0.532[b]
706	534	0	79,700	$-^{c}$	6.70	12.6	0.532[b]
707	534	0	79,700	$-^{c}$	6.70	12.6	0.532[b]
708	657	0	99,000	$-^{c}$	6.64	12.6	0.527[b]
709	657	0	99,000	$-^{c}$	6.64	12.6	0.527[b]
710	657	0	110,000	$-^{c}$	597	12.6	0.474[b]
711	102	0	34,200	$-^{c}$	2.98	11.2	0.266[b]

(continued)

TABLE B-1 (continued)

Plant code	Particulate emissions, tons/yr	Particulate control efficiency, percent	Coal consumption, tons/yr	Controlled particulate emission factor, g/kg	Uncontrolled particulate emission factor, g/kg	Coal ash content, percent	Uncontrolled emission factor divided by ash content[a]
712	102	0	34,200	-[c]	2.98	11.2	0.266[b]
713	102	0	34,200	-[c]	2.98	11.2	0.266[b]
714	102	0	34,200	-[c]	2.98	11.2	0.266[b]
715	102	0	34,200	-[c]	2.98	11.2	0.266[b]
716	102	0	34,200	-[c]	2.98	11.2	0.266[b]
717	102	0	34,200	-[c]	2.98	11.2	0.266[b]
718	102	0	34,200	-[c]	2.98	11.2	0.266[b]
719	102	0	34,200	-[c]	2.98	11.2	0.266[b]
720	102	0	34,200	-[c]	2.98	11.2	0.266[b]
721	1,150	73.0	82,300	14.0	51.8	16.4	3.16
722	102	0	34,200	-[c]	2.98	11.2	0.266[b]
723	102	0	34,200	-[c]	2.98	11.2	0.266[b]
724	102	0	34,200	-[c]	2.98	11.2	0.266[b]
725	1,530	82.0	78,000	19.6	109	16.4	6.65
726	499	80.0	113,000	4.42	22.1	16.4	1.35
727	388	78.0	83,200	4.66	21.2	16.4	1.29
728	1,220	70.0	86,700	14.1	46.9	16.4	2.86
729	761	79.0	67,500	11.3	53.7	16.4	3.27
730	1,320	63.0	75,300	17.5	47.4	16.4	2.89
731	1,280	85.0	75,300	17.0	113	16.4	6.89
736	745	98.0	75,000	9.93	497	15.9	31.3
737	5,510	84.5	165,000	33.4	215	18.2	0.155[b]
738	3,210	84.1	165,000	19.5	122	18.2	6.70
739	3,890	94.5	165,000	23.6	429	18.2	23.6
740	3,100	92.2	165,000	18.8	241	18.2	13.2
741	1,190	97.0	165,000	7.21	240	18.2	13.2
742	13,500	78.0	165,000	81.8	372	18.2	20.4
743	144	0	1,400,000	-[c]	0.103	19.3	0.00534[b]
747	1,490	95.0	751,000	1.98	39.7	12.5	3.18
795	3,640	91.8	181,000	20.1	245	24.7	9.92

(continued)

TABLE B-1 (continued)

Plant code	Particulate emissions, tons/yr	Particulate control efficiency, percent	Coal consumption, tons/yr	Controlled particulate emission factor, g/kg	Uncontrolled particulate emission factor, g/kg	Coal ash content, percent	Uncontrolled emission factor divided by ash content[a]
796	3,640	91.8	181,000	20.1	245	24.7	9.92
797	3,640	91.8	181,000	20.1	245	24.7	9.92
798	3,640	91.8	181,000	20.1	245	24.7	9.92
799	1,090	97.4	343,000	3.18	122	14.1	8.65
800	3,180	93.8	426,000	7.46	120	13.6	8.82
805	4,060	98.1	311,000	13.1	687	20.1	34.2
806	3,070	97.9	311,000	9.87	470	20.1	23.4
807	3,090	97.9	311,000	9.94	473	20.1	23.5
808	1,350	98.3	311,000	4.34	255	20.1	12.7
811	3,070	99.0	909,000	3.38	338	15.0	22.5
812	2,660	97.5	902,000	2.95	118	15.0	7.87
884	159	98.2	1,960,000	0.0811	4.51	15.0	0.301[b]
885	159	98.2	2,140,000	0.743	41.3	15.0	2.75
892	543	99.3	507,000	1.07	153	16.6	9.22
893	543	99.3	507,000	1.07	153	16.6	9.22
900	5,070	97.7	1,630,000	3.11	135	17.5	7.71
901	5,070	97.4	1,630,000	3.11	120	17.5	6.86
917	118	97.0	21,600	5.46	182	11.4	16.0
918	51	97.0	29,000	1.76	58.6	11.4	5.14
919	87	97.0	68,200	1.28	42.5	11.4	3.73
920	260	97.0	116,000	2.24	74.7	11.4	6.55
922	850	97.0	324,000	2.62	87.4	11.4	7.67
932	18	99.8	52,400	0.344	172	11.6	14.8
933	18	85.0	58,500	0.308	2.05	11.6	0.177[b]
960	5,020	85.0	425,000	11.8	78.7	14.0	5.62
961	5,850	85.0	425,000	13.8	91.8	14.0	6.56
962	7,580	85.0	895,000	8.47	56.5	14.0	4.04
963	100	99.7	1,440,000	0.0694	23.1	14.0	1.65
966	1,570	98.0	642,000	2.45	122	6.0	20.3
967	688	99.4	1,090,000	0.631	105	11.0	9.55
6	31	99.3	8,300	3.73	534	15.3	34.9
15	636	99.3	741,000	0.858	123	14.0	8.79
16	710	99.7	849,000	0.836	279	13.7	20.4

(continued)

TABLE B-1 (continued)

Plant code	Particulate emissions, tons/yr	Particulate control efficiency, percent	Coal consumption, tons/yr	Controlled particulate emission factor, g/kg	Uncontrolled particulate emission factor, g/kg	Coal ash content, percent	Uncontrolled emission factor divided by ash content[a]
17	770	99.3	841,000	0.916	131	14.0	9.36
18	721	99.3	841,000	0.857	122	14.0	8.71
19	2,150	99.0	1,800,000	1.19	119	13.0	9.15
21	214	99.3	190,000	1.13	161	14.7	11.0
24	125	99.6	333,000	0.375	93.8	6.0	15.6
25	960	97.0	180,000	5.33	178	8.4	21.2
28	180	98.0	124,000	1.45	72.6	8.1	8.96
36	736	77.0	22,500	3.27	14.2	12.0	1.18
37	736	77.0	22,500	3.27	14.2	12.0	1.18
38	220	99.7	609,000	0.361	120	5.9	20.3
39	220	99.7	609,000	0.361	120	5.9	20.3
52	22	96.0	3,080	7.14	179	9.5	18.8
53	702	99.8	97,400	7.21	3,600	9.5	379[b]
70	21,200	98.6	1,010,000	21.0	1,500	10.9	138[b]
71	2,930	97.8	1,250,000	2.34	107	10.9	9.82
72	60	99.4	1,690,000	0.0355	5.92	10.9	0.543[b]
74	79	96.0	13,200	5.98	150	14.0	10.7
75	53	96.0	13,200	4.02	100	14.0	7.14
76	136	98.7	73,000	1.86	143	14.1	10.1
77	90	99.2	77,000	1.17	146	14.1	10.4
78	153	99.1	133,000	1.15	128	14.1	9.08
79	135	99.1	117,000	1.15	128	14.1	9.08
80	361	99.4	376,000	0.960	160	12.1	13.2
81	321	99.4	425,000	0.755	126	12.1	10.4
89	221	97.1	205,000	1.08	37.2	12.0	3.10
90	211	97.1	205,000	1.03	35.5	12.0	2.96
91	660	97.6	317,000	2.08	86.8	10.2	8.51
92	683	97.5	317,000	2.15	86.2	10.2	8.45
93	882	96.9	328,000	2.69	65.6	10.2	6.43
94	1,030	98.1	466,000	2.21	116	10.2	11.4
95	1,240	97.8	466,000	2.66	121	13.8	8.77
96	917	98.5	432,000	2.12	142	13.8	10.3
97	1,510	98.6	873,000	1.73	124	13.8	8.99

(continued)

TABLE B-1 (continued)

Plant code	Particulate emissions, tons/yr	Particulate control efficiency, percent	Coal consumption, tons/yr	Controlled particulate emission factor, g/kg	Uncontrolled particulate emission factor, g/kg	Coal ash content, percent	Uncontrolled emission factor divided by ash content[a]
98	2,450	97.5	588,000	4.17	167	13.8	12.1
196	3,780	89.2	713,000	5.30	49.1	8.7	5.64
223	816	98.4	469,000	1.74	109	12.8	8.52
224	918	98.3	497,000	1.85	109	12.8	8.52
225	9,380	88.0	718,000	13.1	109	12.8	8.52
240	63	97.0	31,000	2.03	67.7	8.0	8.46
241	58	98.5	57,000	1.02	67.8	8.0	8.46
Average uncontrolled emission factor (A = coal ash content in percent)							10.5A
Average controlled emission factor (Based on high efficiency units)				0.21A			

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[a] This column was used to check emissions data and control efficiencies reported in NEDS. Material balance considerations show the maximum possible value to be $\sim$10.

[b] Not included in average.

[c] Not applicable.

TABLE B-2. SO_x EMISSIONS DATA FOR UTILITY BOILERS BURNING PULVERIZED BITUMINOUS COAL (DRY BOTTOM)

Plant code	SO_x emissions, tons/yr	Coal consumption, tons/yr	Uncontrolled SO_x emission factor, g/kg	Coal sulfur content, percent	SO_x emission factor divided by coal sulfur content[a]
16	710	849,000	0.836	1.66	0.504[b]
17	41,000	841,000	48.8	0.89	54.8[b]
21	5,110	190,000	26.9	1.40	19.2
24	3,100	330,000	9.39	0.60	15.7
38	8,600	609,000	14.1	0.42	33.6
39	8,600	609,000	14.1	0.42	33.6
240	1,610	31,000	51.9	2.73	19.0
241	2,920	57,000	51.2	2.70	19.0
672	133	10,000	13.3	1.00	13.3
673	79	6,000	13.2	1.00	13.2
674	252	19,000	13.3	1.00	13.3
675	824	62,000	13.3	1.00	13.3
683	2,620	29,900	89.0	0.90	98.9[b]
684	2,660	52,500	50.7	0.90	56.3[b]
685	2,480	151,000	16.4	0.90	18.2
686	2,960	106,000	27.9	0.90	31.0
687	2,350	136,000	17.3	0.90	19.2
688	1,920	77,200	24.9	0.90	27.7
705	2,300	79,700	28.9	1.74	16.6
706	2,300	79,700	28.9	1.74	16.6
707	2,300	79,700	28.9	1.74	16.6
708	3,110	99,000	31.4	1.74	18.0
709	3,110	99,000	31.4	1.74	18.0
710	3,110	110,000	28.3	1.74	16.3
711	113	34,200	3.30	2.00	1.65[b]
712	113	34,200	3.30	2.00	1.65[b]
713	113	34,200	3.30	2.00	1.65[b]
714	113	34,200	3.30	2.00	1.65[b]
715	113	34,200	3.30	2.00	1.65[b]
716	113	34,200	3.30	2.00	1.65[b]
717	113	34,200	3.30	2.00	1.65[b]
718	113	34,200	3.30	2.00	1.65[b]
719	113	34,200	3.30	2.00	1.65[b]
720	113	34,200	3.30	2.00	1.65[b]
721	1,730	82,300	21.0	1.00	21.0
722	113	34,200	3.30	2.00	1.65[b]
723	113	34,200	3.30	2.00	1.65[b]
724	113	34,200	3.30	2.00	1.65[b]
725	2,220	78,000	28.5	1.00	28.5

(continued)

TABLE B-2 (continued)

Plant code	SO_x emissions, tons/yr	Coal consumption, tons/yr	Uncontrolled SO_x emission factor, g/kg	Coal sulfur content, percent	SO_x emission factor divided by coal sulfur content[a]
726	1,290	113,000	11.4	1.00	11.4
727	459	83,200	5.52	1.00	5.52
728	1,220	86,700	14.1	1.00	14.1
729	893	67,500	13.2	1.00	13.2
730	891	78,000	11.4	1.00	11.4
731	2,300	75,300	30.5	1.00	30.5
737	5,270	165,000	31.9	1.84	17.3
738	5,270	165,000	31.9	1.84	17.3
739	8,700	165,000	52.7	1.84	28.6
740	8,700	165,000	52.7	1.84	28.6
741	8,700	165,000	52.7	1.84	28.6
742	12,700	165,000	77.0	1.84	41.8[b]
743	95	1,400,000	0.0679	2.21	0.0307[b]
771	3,150	51,000	61.8	1.36	45.4[b]
772	3,150	51,000	61.8	1.36	45.4[b]
795	23,000	181,000	127	3.00	42.3[b]
796	23,000	181,000	127	3.00	42.3[b]
797	23,000	181,000	127	3.00	42.3[b]
798	23,000	181,000	127	3.00	42.3[b]
799	20,500	343,000	59.8	3.00	19.9
800	26,300	426,000	61.7	3.00	20.6
805	11,600	311,000	37.3	2.17	17.2
806	12,300	311,000	39.5	2.17	18.2
807	13,300	311,000	42.8	2.17	19.7
808	20,600	311,000	66.2	2.17	30.5
960	4,770	425,000	11.2	0.50	22.4
961	4,920	425,000	11.6	0.50	23.2
962	6,240	895,000	6.97	0.50	13.58
963	3,680	1,440,000	2.56	0.50	5.12
967	8,350	1,090,000	7.66	0.50	15.3
Average emission factor (S = coal sulfur content in percent)					19.4S

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[a] This column was used to check emissions data reported in NEDS. Material balance considerations show the maximum possible value to be 20.

[b] Not included in average.

TABLE B-3. NO_x EMISSIONS DATA FOR UTILITY BOILERS BURNING PULVERIZED BITUMINOUS COAL (DRY BOTTOM)

Plant code	NO_x emissions, tons/yr	Coal consumption, tons/yr	NO_x emission factor, g/kg
38	6,300	609,000	10.3
52	13	3,080	4.22
240	368	31,000	11.9
241	655	57,000	11.5
473	9,540	486,000	19.6
474	7,930	486,000	16.3
475	10,200	626,000	16.3
476	26,600	626,000	42.5[a]
477	8,630	1,260,000	6.85
672	90	10,000	9.00
673	54	6,000	9.00
674	171	19,000	9.00
675	465	62,000	7.50
683	1,240	29,900	41.5[a]
684	1,070	52,500	20.4
685	1,170	151,000	7.75
686	1,400	106,000	13.2
687	110	136,000	0.809[a]
688	911	77,200	11.8
967	4,990	1,090,000	4.58
Average emission factor			11

[a] Not included in average.

TABLE B-4. HYDROCARBON EMISSIONS DATA FOR UTILITY BOILERS BURNING PULVERIZED BITUMINOUS COAL (DRY BOTTOM)

Plant code	Hydrocarbon emissions, tons/yr	Coal consumption, tons/yr	Hydrocarbon emission factor, g/kg
240	14	31,000	0.452
241	24	57,000	0.421
672	1	10,000	0.100
674	2	19,000	0.105
675	31	62,000	0.500
683	20	29,900	0.669
684	17	52,500	0.324
685	19	151,000	0.126
686	23	106,000	0.217
687	18	136,000	0.132
688	15	77,200	0.194
Average emission factor			0.295

TABLE B-5. CO EMISSIONS DATA FOR UTILITY BOILERS BURNING PULVERIZED BITUMINOUS COAL (DRY BOTTOM)

Plant code	CO emissions, tons/yr	Coal consumption, tons/yr	CO emission factor, g/kg
240	16	31,000	0.516
241	29	57,000	0.509
672	5	10,000	0.500
673	3	6,000	0.500
674	9	19,000	0.474
675	62	62,000	1.00
683	68	29,900	2.27
684	59	52,500	1.12
685	65	151,000	0.430
686	77	106,000	0.726
687	61	136,000	0.449
688	50	77,200	0.648
Average emission factor			0.76

APPENDIX C

DERIVATION OF AMBIENT SEVERITY EQUATIONS

SUMMARY OF SEVERITY EQUATIONS FOR AIR POLLUTANTS

The ambient severity (S) of pollutants may be calculated using the mass emission rate (Q), the height of the emissions (H), the ambient air quality standard (for criteria pollutants), and the threshold limit value (TLV) (for noncriteria pollutants) [65]. The equations summarized in Table C-1 are developed in detail in this appendix.

TABLE C-1. AMBIENT SEVERITY EQUATIONS FOR ELEVATED POINT SOURCES

Pollutants	Severity equation
Particulate	$S_P = \frac{70\ Q}{H^2}$
SO_2	$S_{SO_2} = \frac{50\ Q}{H^2}$
NO_2	$S_{NO_2} = \frac{315\ Q}{H^{2.1}}$
Hydrocarbon	$S_{HC} = \frac{162\ Q}{H^2}$
CO	$S_{CO} = \frac{0.78\ Q}{H^2}$
Other	$S_a = \frac{5.5\ Q}{TLV \bullet H^2}$

DERIVATION OF χ_{max} FOR USE WITH U.S. AVERAGE CONDITIONS

The most widely accepted formula for predicting downwind ground level concentrations from a point source is [59]:

$$\chi = \frac{Q}{\pi \sigma_y \sigma_z u} \exp\left[-\frac{1}{2}\left(\frac{y}{\sigma_y}\right)^2\right] \exp\left[-\frac{1}{2}\left(\frac{H}{\sigma_z}\right)^2\right] \quad \text{(C-1)}$$

where χ = downwind ground level concentration at reference coordinate x and y with emission height of H, g/m³

Q = mass emission rate, g/s

π = 3.14

σ_y = standard deviation of horizontal dispersion, m

σ_z = standard deviation of vertical dispersion, m

u = wind speed, m/s

y = horizontal distance from centerline of dispersion, m

H = height of emission release, m

x = downwind dispersion distance from source of emission release, m

We assume that χ_{max} occurs when x is much greater than 0 and y equals 0. For a given stability class, standard deviations of horizontal and vertical dispersion have often been expressed as a function of downwind distance by power law relationships as follows [124].

$$\sigma_y = ax^b \tag{C-2}$$

$$\sigma_z = cx^d + f \tag{C-3}$$

Values for a, b, c, d, and f are given in Tables C-2 [125] and C-3. Substituting these general equations into Equation C-1 yields

$$\chi = \frac{Q}{ac\pi ux^{b+d} + a\pi ufx^b} \exp\left[-\frac{H^2}{2(cx^d + f)^2}\right] \tag{C-4}$$

Assuming that χ_{max} occurs at x less than 100 m and the stability class is C, then f equals 0 and Equation C-4 becomes

$$\chi = \frac{Q}{ac\pi ux^{b+d}} \exp\left[\frac{-H^2}{2c^2x^{2d}}\right] \tag{C-5}$$

For convenience, let

$$A_R = \frac{Q}{ac\pi u} \text{ and } B_R = \frac{-H^2}{2c^2}$$

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[124] Martin, D. O., and J. A. Tikvart. A General Atmospheric Diffusion Model for Estimating the Effects on Air Quality of One or More Sources. Presented at the 61st Annual Meeting of the Air Pollution Control Association, St. Paul, Minnesota, June 23-27, 1968. 18 pp.

[125] Eimutis, E. C., and M. G. Konicek. Derivations of Continuous Functions for the Lateral and Vertical Atmospheric Dispersion Coefficients. Atmospheric Environment, 3(6): 688-689, 1969.

TABLE C-2. VALUES OF a FOR THE COMPUTATION OF σ_y[a] [126]

Stability class	a
A	0.3658
B	0.2751
C	0.2089
D	0.1471
E	0.1046
F	0.0722

[a] For the Equation C-2:

$$\sigma_y = ax^b$$

where x = downwind distance
b = 0.9031 (from Reference 126)

TABLE C-3. VALUES OF THE CONSTANTS USED TO ESTIMATE VERTICAL DISPERSION[a] [124]

Usable range, m	Stability class	Coefficient		
		c_1	d_1	f_1
>1,000	A	0.00024	2.094	-9.6
	B	0.055	1.098	2.0
	C	0.113	0.911	0.0
	D	1.26	0.516	-13
	E	6.73	0.305	-34
	F	18.05	0.18	-48.6
		c_2	d_2	f_2
100 to 1,000	A	0.0015	1.941	9.27
	B	0.028	1.149	3.3
	C	0.113	0.911	0.0
	D	0.222	0.725	-1.7
	E	0.211	0.678	-1.3
	F	0.086	0.74	-0.35
		c_3	d_3	f_3
<100	A	0.192	0.936	0
	B	0.156	0.922	0
	C	0.116	0.905	0
	D	0.079	0.881	0
	E	0.063	0.871	0
	F	0.053	0.814	0

[a] For Equation C-3: $\sigma_z = cx^d + f$

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[126] Tadmor, J., and Y. Gur. Analytical Expressions for the Vertical and Lateral Dispersion Coefficients in Atmospheric Diffusion. Atmospheric Environment, 3(6):688-689, 1969.

so that Equation C-5 reduces to

$$\chi = A_R x^{-(b+d)} \exp\left[\frac{B_R}{x^{2d}}\right] \qquad \text{(C-6)}$$

Taking the first derivative of Equation C-6

$$\frac{d\chi}{dx} = A_R \left\{ x^{-b-d} \left(\exp\left[B_R x^{-2d}\right]\right)\left(-2dB_R x^{-2d-1}\right) + \exp\left[B_R x^{-2d}\right]\left(-b-d\right) x^{-b-d-1} \right\} \qquad \text{(C-7)}$$

and setting this equal to zero (to determine the roots which give the minimum and maximum conditions of χ with respect to x) yields

$$\frac{d\chi}{dx} = 0 = A_R x^{-b-d-1} \left[\exp\left(B_R x^{-2d}\right)\right]\left(-2dB_R x^{-2d} - b - d\right) \qquad \text{(C-8)}$$

Since we define that $x \neq 0$ or ∞ at χ_{max}, the following expression must be equal to 0.

$$-2dB_R x^{-2d} - d - b = 0 \qquad \text{(C-9)}$$

or

$$(b+d)x^{2d} = -2dB_R \qquad \text{(C-10)}$$

or

$$x^{2d} = \frac{-2dB_R}{b+d} = \frac{2dH^2}{2c^2(b+d)} \qquad \text{(C-11)}$$

or

$$x^{2d} = \frac{dH^2}{c^2(b+d)} \qquad \text{(C-12)}$$

Hence

$$x = \left(\frac{dH^2}{c^2(b+d)}\right)^{1/2d} \text{ at } \chi_{max} \qquad \text{(C-13)}$$

Thus Equations C-2 and C-3 (at f = 0) become

$$\sigma_y = a\left(\frac{dH^2}{c^2(d+b)}\right)^{b/2d} \qquad \text{(C-14)}$$

$$\sigma_z = c\left[\frac{dH^2}{c^2(b+d)}\right]^{d/2d} = \left(\frac{dH^2}{b+d}\right)^{1/2} \qquad \text{(C-15)}$$

The maximum will be determined for U.S. average conditions of stability. According to Gifford [127], this is when σ_y equals σ_z.

Since b equals 0.9031, and upon inspection of Table C-2 under U.S. average conditions, σ_y equals σ_z, it can be seen that 0.881 is less than or equal to d which is less than or equal to 0.905 (class C stability[a]). Thus, it can be assumed that b is nearly equal to d or in Equations C-14 and C-15 or

$$\sigma_z = \frac{H}{\sqrt{2}} \qquad \text{(C-16)}$$

and

$$\sigma_y = \frac{a}{c}\,\frac{H}{\sqrt{2}} \qquad \text{(C-17)}$$

Under U.S. average conditions, σ_y equals σ_z and a approximates c if b approximates d and f equals 0 (between class C and D, but closer to belonging in class C).

Then

$$\sigma_y = \frac{H}{\sqrt{2}} \qquad \text{(C-18)}$$

Substituting for σ_y from Equation C-18 and for σ_z from Equation C-16 into Equation C-1 and letting y equal 0

$$\chi_{max} = \frac{2\ Q}{\pi u H^2}\exp\left[-\frac{1}{2}\left(\frac{H\sqrt{2}}{H}\right)^2\right] \qquad \text{(C-19)}$$

or

$$\chi_{max} = \frac{2\ Q}{\pi e u H^2} \qquad \text{(C-20)}$$

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[a] The values given in Table C-3 are mean values for stability class. Class C stability describes these coefficients and exponents, only within about a factor of two.

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[127] Gifford, F. A., Jr. An Outline of Theories of Diffusion in the Lower Layers of the Atmosphere. In: Meteorology and Atomic Energy 1968, Chapter 3, D. A. Slade, ed. Publication No. TID-24190, U.S. Atomic Energy Commission Technical Information Center, Oak Ridge, Tennessee, July 1968. p. 113.

For U.S. average conditions, u equals 4.47 m/s so that Equation C-20 reduces to

$$\chi_{max} = \frac{0.0524\ Q}{H^2} \qquad \text{(C-21)}$$

DEVELOPMENT OF AMBIENT SEVERITY EQUATIONS

Ambient severity, S_a, has been defined as follows:

$$S_a = \frac{\bar{\chi}_{max}}{F} \qquad \text{(C-22)}$$

where $\bar{\chi}_{max}$ = time-averaged maximum ground level concentration
F = ambient environmental goal; for criteria pollutants, F = AAQS; for noncriteria pollutants, F = TLV • 8/24 • 1/100.

Noncriteria Emissions

The value of $\bar{\chi}_{max}$ may be derived from χ_{max}, and undefined "short-term" concentration. An approximation for longer term concentration may be made as follows:

For a 24-hr time period,

$$\bar{\chi}_{max} = \chi_{max} \left(\frac{t_o}{t}\right)^{0.17} \qquad \text{(C-23)}$$

where t_o = instantaneous (i.e., 3-min) averaging time
t = averaging time period used (i.e., 24 hr or 1,440 min)

Hence

$$\bar{\chi}_{max} = \chi_{max} \left(\frac{3\ \text{min}}{1{,}440\ \text{min}}\right)^{0.17} \qquad \text{(C-24)}$$

$$\bar{\chi}_{max} = \chi_{max}\ (0.35) \qquad \text{(C-25)}$$

Since the environmental goal is defined and derived from TLV values as follows:

$$F = (\text{TLV})\left(\frac{8}{24}\right)\left(\frac{1}{100}\right) \qquad \text{(C-26)}$$

$$F = (3.33 \times 10^{-3})\ \text{TLV} \qquad \text{(C-27)}$$

then severity, S_a, is defined as

$$S_a = \frac{\bar{\chi}_{max}}{F} = \frac{0.35\ \chi_{max}}{(3.33 \times 10^{-3})\ \text{TLV}} \qquad \text{(C-28)}$$

$$S_a = \frac{105\ \chi_{max}}{TLV} \qquad (C-29)$$

If a weekly averaging period is used, then

$$\bar{\chi}_{max} = \chi_{max}\left(\frac{3}{10,080}\right)^{0.17} \qquad (C-30)$$

or

$$\bar{\chi}_{max} = 0.25\ \chi_{max} \qquad (C-31)$$

and

$$F = (TLV)\left(\frac{40}{168}\right)\left(\frac{1}{100}\right) \qquad (C-32)$$

$$F = (2.38 \times 10^{-3})TLV \qquad (C-33)$$

and severity, S_a, is

$$S_a = \frac{\bar{\chi}_{max}}{F} = \frac{0.25\ \chi_{max}}{(2.38 \times 10^{-3})TLV} \qquad (C-34)$$

or

$$S_a = \frac{105\ \chi_{max}}{TLV} \qquad (C-35)$$

which is entirely consistent, since the TLV is being corrected for a different exposure period.

Therefore, the severity can be derived from χ_{max} directly without regard to averaging time for noncriteria emissions. Thus, combining Equations C-35 and C-21, for elevated sources, gives

$$S_a = \frac{5.5\ Q}{TLV \bullet H^2} \qquad (C-36)$$

Criteria Emissions

For the criteria pollutants, established standards may be used as F values in Equation C-22. These are given in Table C-4 [62-64]. However, Equation C-23 must be used to give the appropriate averaging period. These equations are developed for elevated sources using Equation C-21.

TABLE C-4. SUMMARY OF NATIONAL AMBIENT AIR QUALITY STANDARDS [62-64]

Pollutant	Averaging time	Primary standards, μg/m³	Secondary standards, μg/m³
Particulate matter	Annual (geometric mean)	75	60[a]
	24-hr[b]	260	150
SO_2	Annual (arithmetic mean)	80	–[c]
	24-hr[b]	365	–[c]
	3-hr[b]	–[c]	1,300
CO	8-hr[b]	10,000	10,000
	1-hr[b]	40,000	40,000
Nitrogen dioxide	Annual (arithmetic mean)	100	100
Ozone	1-hr[b]	235	235
Hydrocarbons (nonmethane)	3-hr (6 a.m. to 9 a.m.)	160[d]	160

[a] The secondary annual standard (60 μg/m³) is a guide for assessing implementation plans to achieve the 24-hr secondary standard.

[b] Not to be exceeded more than once per year.

[c] No standard exists.

[d] There is no primary ambient air quality standard for hydrocarbons. The value of 160 μg/m³ used for hydrocarbons in this report is an EPA-recommended guideline for meeting the primary ambient air quality standard for ozone.

Carbon Monoxide Severity--

The primary standard for CO is reported for a 1-hr averaging time. Therefore

$$t = 60 \text{ min}$$

$$t_o = 3 \text{ min}$$

$$\bar{\chi}_{max} = \chi_{max} \left(\frac{3}{60}\right)^{0.17} \qquad \text{(C-37)}$$

$$= \frac{2\ Q}{\pi e u H^2} \left(\frac{3}{60}\right)^{0.17} \qquad \text{(C-38)}$$

$$= \frac{2\ Q}{(3.14)(2.72)(4.5)H^2}\ 0.6 \qquad \text{(C-39)}$$

$$\bar{\chi}_{max} = \frac{0.052\ Q}{H^2}\ 0.6 \qquad \text{(C-40)}$$

$$\bar{\chi}_{max} = \frac{(3.12 \times 10^{-2})Q}{H^2} \qquad \text{(C-41)}$$

$$\text{Severity, } S = \frac{\bar{X}_{max}}{F} \qquad (C\text{-}42)$$

Setting F equal to the primary AAQS for CO or 0.04 g/m³ yields

$$S = \frac{\bar{X}_{max}}{F} = \frac{(3.12 \times 10^{-2})Q}{0.04\ H^2} \qquad (C\text{-}43)$$

or

$$S_{CO} = \frac{0.78\ Q}{H^2} \qquad (C\text{-}44)$$

Hydrocarbon Severity--

The primary standard for nonmethane hydrocarbons is reported for a 3-hr averaging time.

$$t = 180 \text{ min}$$

$$t_0 = 3 \text{ min}$$

$$\bar{X}_{max} = X_{max} \left(\frac{3}{180}\right)^{0.17} \qquad (C\text{-}45)$$

$$= 0.5\ X_{max} \qquad (C\text{-}46)$$

$$= \frac{(0.5)(0.052)Q}{H^2} \qquad (C\text{-}47)$$

$$\bar{X}_{max} = \frac{0.026\ Q}{H^2} \qquad (C\text{-}48)$$

For nonmethane hydrocarbons, the concentration of 1.6 x 10^{-4} g/m³ has been issued as a guideline for achieving oxidant standards. Therefore,

$$S = \frac{\bar{X}_{max}}{F} = \frac{0.026\ Q}{1.6 \times 10^{-4}\ H^2} \qquad (C\text{-}49)$$

or

$$S_{HC} = \frac{162.5\ Q}{H^2} \qquad (C\text{-}50)$$

Particulate Severity--

The primary standard for particulate matter is reported for a 24-hr averaging time.

$$\bar{X}_{max} = X_{max}\left(\frac{3}{1,440}\right)^{0.17} \qquad \text{(C-51)}$$

$$= \frac{(0.35)(0.052)Q}{H^2} \qquad \text{(C-52)}$$

$$\bar{X}_{max} = \frac{0.0182\ Q}{H^2} \qquad \text{(C-53)}$$

For particulate matter, F equals the primary AAQS 2.6 x 10^{-4} g/m^3, and

$$S = \frac{\bar{X}_{max}}{F} = \frac{0.0182\ Q}{(2.6 \times 10^{-4})H^2} \qquad \text{(C-54)}$$

$$S_P = \frac{70\ Q}{H^2} \qquad \text{(C-55)}$$

SO_2 Severity--
The primary standard for SO_2 is reported for a 24-hr averaging time. Using t = 1,440 minutes and proceeding as before:

$$\bar{X}_{max} = \frac{0.0182\ Q}{H^2} \qquad \text{(C-56)}$$

The primary AAQS for SO_2 is 3.65 x 10^{-4} g/m^3. Therefore,

$$S_a = \frac{\bar{X}_{max}}{F} = \frac{0.0182\ Q}{(3.65 \times 10^{-4})H^2} \qquad \text{(C-57)}$$

or

$$S_{SO_2} = \frac{50\ Q}{H^2} \qquad \text{(C-58)}$$

NO_2 Severity--
Since NO_2 has a primary standard with a 1-yr averaging time, the X_{max} correction equation cannot be used. As an alternative, the following equation is used:

$$\bar{X} = \frac{2.03\ Q}{\sigma_z ux} \exp\left[-\frac{1}{2}\left(\frac{H}{\sigma_z}\right)^2\right] \qquad \text{(C-59)}$$

A difficulty arises, however, because a distance x, from emission point to receptor, is included; hence, the following rationale is used:

$$X_{max} = \frac{2\ Q}{\pi e u H^2} \qquad \text{(C-20)}$$

Equation C-20, shown earlier, is valid for neutral conditions or when σ_z approximately equals σ_y.

This maximum occurs when

$$H = \sqrt{2}\sigma_z \tag{C-60}$$

and since, under these conditions,

$$\sigma_z = ax^b \tag{C-61}$$

then the distance, x_{max}, where the maximum concentration occurs is

$$x_{max} = \left(\frac{H}{\sqrt{2}a}\right)^{1/b} \tag{C-62}$$

For class C conditions, a = 0.113 and b = 0.911. Substituting these values into Equation C-62 yields:

$$x_{max} = \frac{H^{1.098}}{0.16} = 7.5\ H^{1.098} \tag{C-63}$$

Since

$$\sigma_z = 0.113\ x_{max}{}^{0.911} \tag{C-64}$$

and

$$\bar{u} = 4.5 \text{ m/s}$$

and letting $x = x_{max}$, Equation C-59 becomes

$$\bar{\chi}_{max} = \frac{4\ Q}{x_{max}{}^{1.911}} \exp\left[-\frac{1}{2}\left(\frac{H}{\sigma_z}\right)^2\right] \tag{C-65}$$

where

$$\frac{4\ Q}{x_{max}{}^{1.911}} = \frac{4\ Q}{(7.5\ H^{1.098})^{1.911}} \tag{C-66}$$

Therefore,

$$\bar{\chi}_{max} = \frac{0.085\ Q}{H^{2.1}} \exp\left[-\frac{1}{2}\left(\frac{H}{\sigma_z}\right)^2\right] \tag{C-67}$$

As noted above,

$$\sigma_z = 0.113\ x^{0.911} \qquad \text{(C-64)}$$

Substituting for x yields

$$\sigma_z = 0.113(7.5\ H^{1.1})^{0.911} \qquad \text{(C-68)}$$

or

$$\sigma_z = 0.71\ H \qquad \text{(C-69)}$$

Therefore,

$$\overline{X}_{max} = \frac{0.085\ Q}{H^{2.1}} \exp\left[-\frac{1}{2}\left(\frac{H}{0.71\ H}\right)^2\right] \qquad \text{(C-70)}$$

$$= \frac{0.085\ Q}{H^{2.1}}\ (0.371) \qquad \text{(C-71)}$$

$$\overline{X}_{max} = \frac{3.15 \times 10^{-2}\ Q}{H^{2.1}} \qquad \text{(C-72)}$$

Since the AAQS for NO_2 1.0×10^{-4} g/m^3, the NO_x severity equation is

$$S_{NO_2} = \frac{(3.15 \times 10^{-2})Q}{1 \times 10^{-4}\ H^{2.1}} \qquad \text{(C-73)}$$

$$S_{NO_2} = \frac{315\ Q}{H^{2.1}} \qquad \text{(C-74)}$$

AFFECTED POPULATION CALCULATION

Another form of the plume dispersion equation is needed to calculate the affected population since the population is assumed to be distributed uniformly around the source. If the wind directions are taken to 16 points and it is assumed that the wind directions within each sector are distributed randomly over a period of a month or a season, it can be assumed that the effluent is uniformly distributed in the horizontal within the sector. The appropriate equation for average concentration, $\overline{X}$, in grams per cubic meter is then (for 100 m $\leq$ x $\leq$ 1,000 m and stability class C) [66]:

$$\overline{X} = \frac{2.03\ Q}{\sigma_z u x} \exp\left[-\frac{1}{2}\left(\frac{H}{\sigma_z}\right)^2\right] \qquad \text{(C-75)}$$

To find the distances at which $\overline{\chi}$/AAQS equals 1.0, roots are determined for the following equation:

$$\frac{2.03\ Q}{(\mathrm{AAQS})\sigma_z ux} \exp\left[-\frac{1}{2}\left(\frac{H}{\sigma_z}\right)^2\right] = 1.0 \qquad \text{(C-76)}$$

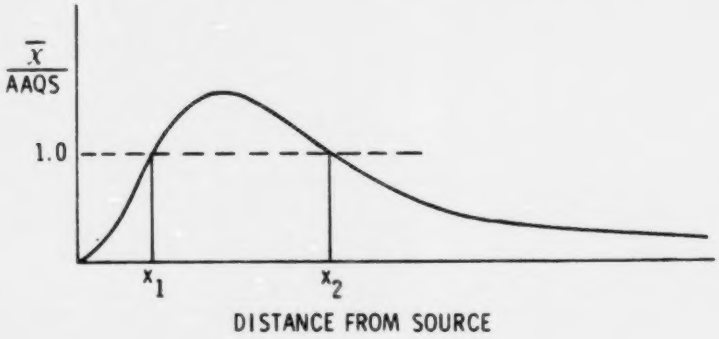
keeping in mind that

$$\sigma_z = ax^b + c$$

where a, b, and c are functions of atmospheric stability and are assumed to be selected for stability Class C.

Since Equation C-76 is a transcendental equation, the roots are found by an iterative technique using the computer.

For a specified emission from a typical source, $\overline{\chi}$/AAQS as a function of distance might look as follows:



The affected population is contained in the area

$$A = \pi(x_2^2 - x_1^2) \qquad \text{(C-77)}$$

If the affected population density is D_p, the total affected population, P', is

$$P' = D_pA \text{ (persons)} \qquad \text{(C-78)}$$

AMBIENT EFFLUENT SEVERITY

Various mathematical models can be conceived to describe the impact of a discharge on a receiving body. Such systems are complex and not fully understood. Pertinent factors deserving consideration include the number of discharge streams; the flow rate and composition (chemical and physical characteristics) of each discharge stream; the hazardous nature of the discharge; the volume, flow rate, and water quality of the receiving body; and the ability of the receiving body to detoxify the discharge. In an effluent stream containing many materials, each species may have a different environmental impact; in addition, synergestic interactions may occur.

For this assessment study, it was decided to adopt a simplified approach in which the resultant concentration of a specific pollutant is compared to an associated environmental goal. Three simple models can be considered depending on the degree of mixing with the receiving body. In the first case, the effluent severity (S_e) was defined for each discharge as follows:

$$S_{BD} = \frac{C_D}{F_e} \qquad \text{(C-79)}$$

where S_{BD} = effluent severity due to a pollutant in a discharge stream before dilution
C_D = concentration of pollutant in effluent, g/m³
F_e = environmental goal, equal to a potentially hazardous concentration, g/m³

Equation C-79 describes what may be termed the end-of-pipe severity for the discharge stream. Once an effluent enters a receiving body, it is diluted by the receiving body water and the severity decreases. The effluent severity within a mixing zone is defined as follows:

$$S_{MZ} = \left(\frac{V_D}{V_D + F_{MZ} \bullet vr}\right)\left(\frac{C_D}{F_e}\right) \qquad \text{(C-80)}$$

where S_{MZ} = effluent severity due to a pollutant in a mixing zone
V_D = effluent discharge rate, m³/s
vr = river flow rate, m³/s
F_{MZ} = fraction of river flow in mixing zone; i.e., 1/3, 1/4

The severity after the mixing zone, S_{AMZ}, is given by:

$$S_{AMZ} = \left(\frac{V_D}{V_D + vr}\right)\left(\frac{C_D}{F_e}\right) \qquad \text{(C-81)}$$

where S_{AMZ} = effluent severity due to a pollutant after a mixing zone

These relationships are shown in Figure C-1

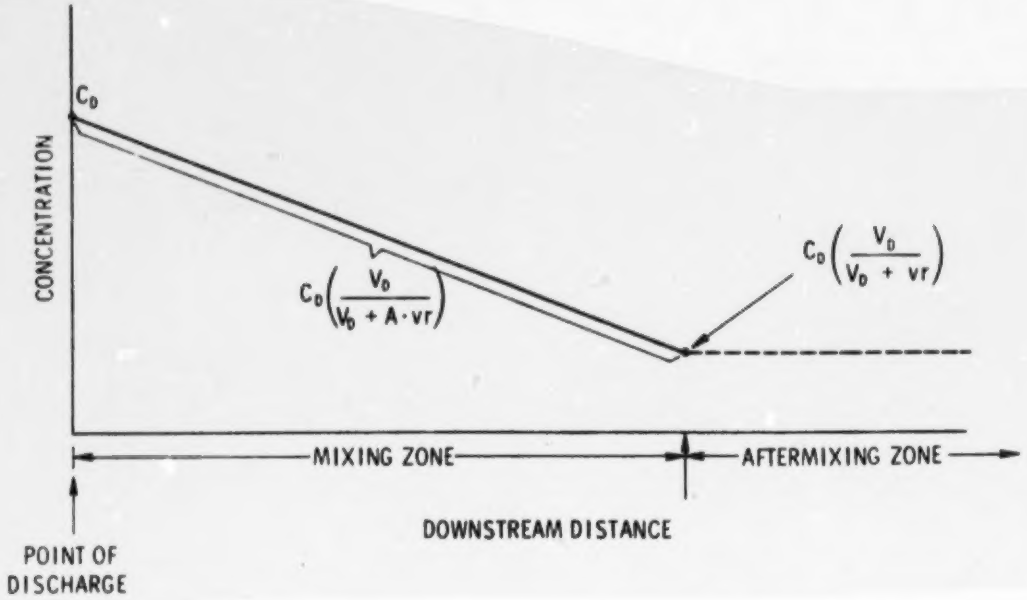


Figure C-1. Change of concentration with distance.

If vr is much greater than V_D, then

$$S_{AMZ} = \left(\frac{V_D}{vr}\right)\left(\frac{C_D}{F_e}\right) \tag{C-82}$$

Equation C-82 defines the ambient effluent severity, S_e, used in this report. It is important to note that this effluent severity is not an aggregate parameter; instead, it refers to one pollutant within one discharge stream. A more detailed treatment of the effluent severity is available in the literature [98].

APPENDIX D

ANALYSIS OF UTILITY PLANT SOLID AND SLURRY SAMPLES

SUMMARY

A series of liquid and solid residue samples were received from a cooperating utility plant (a dry bottom pulverized bituminous unit) for analysis by MRC (Table D-1). The solid-liquid slurries were filtered and carried through the analysis scheme as a "solid portion" and a "liquid portion".

TABLE D-1. LIST OF SAMPLES RECEIVED

Sample	Sample designation
1 (solid)	Dry ESP composite, 8/19/76
2 (solid)	Pyrite, utility plant, 8/18/76
3 (solid)	Pulverizer in glass
4 (solid)	Dry ESP composite, 8/18/76
5 (slurry)	ESP fly ash, 8/19/76, 12:29-1:20 p.m.
6 (slurry)	ESP fly ash, 8/18/76, 8:30-9:20 a.m.
7 (slurry)	Bottom ash, 8/19/76
8 (slurry)	Bottom ash, 8/18/76, 3:27-3:55 p.m.
9 (slurry)	ESP fly ash, 8/18/76, 2:46-3:58 p.m.

Samples were analyzed for POM's and PCB's by GC/MS. No PCB's were detected in any of the samples. POM's were found in all but one of the samples; however, only two samples (Numbers 2 and 3) contained POM's in appreciable quantities (i.e., >1 μg). Detailed results are presented in the text.

In addition to organic analysis, the samples were analyzed for total chlorine, ionic chlorine, total organic carbon, and sulfur. The liquid samples were also analyzed for trace elements with the Jarrel Ash Atomcomp (ICAP). Chlorine concentrations ranged in general from 10 ppm to 40 ppm. Two samples (Numbers 2 and 3) with concentrations in excess of 1,000 ppm are probably in error;

the samples have high sulfur levels (22% and 4%), and the analytical technique is not reliable under these conditions. Trace elements found in the liquid filtrates at levels in excess of 1 ppm were Ba, B, Ca, Mg, Mo, Na, and Si. Complete results are presented in the remainder of the report.

ANALYTICAL PROCEDURES

Sample Preparation

The samples from the utility site were received at MRC in damaged condition. The samples were shipped in glass mason jars and packed in cartons with dry ice. Some jars were broken on arrival. On other jars, the label had either fallen off or smeared beyond legibility. Nine distinct samples and duplicates were received in good condition with adequate identification. Four were solids, while five samples were slurries. The slurries were filtered and carried through the analysis scheme as a "solid portion" and a "liquid portion". This yielded fourteen samples for analysis, plus a "blank".

POM and PCB Workup Procedure

Solid samples were milled to pass through a 200-mesh screen. Aliquots were weighed, and then CH_2Cl_2 extracted via Soxhlet apparatus. Liquid portions were extracted with CH_2Cl_2 via sep-funnel. These extracts were then concentrated via flash-evaporator to 1.0 ml. Further separation of the concentrates was effected via column chromatography. The fractionation scheme described in Appendix A was used to obtain eight fractions per sample. Fractions were scanned for the classes of materials of interest. A Hewlett-Packard 5982-A GC/MS and data system was used for analysis.

The fractions were, at first, scanned in the "Total Ion Mode" to check for the presence of PCB's. Sample volume was then reduced by drying in a stream of N_2. This was followed by redissolving in 1 ml of CH_2Cl_2. At this volume, samples were quantitated using the Selected Ion Monitoring Mode of the GC/MS.

A blank (extract of Soxhlet timble and glass wool) was analyzed. POM's were detected only in the third elution fraction, with the following composition:

Material	Amount
methylanthracenes/phenanthrenes	0.060 µg
dimethylanthracene/phenanthrenes	0.133 µg
fluoranthene	0.061 µg
pyrene	0.092 µg

No PCB's were detected in any of the samples. The detection limit by GC/MS technique for PCB's at MRC's Dayton Laboratory is 1 μg/ml based on standards of individual PCB isomers. Since the volume run for each sample was 1 ml, it can be inferred that no single PCB was present at or above 1 μg.

Total Chlorine and Ionic Chlorine

Total chlorine analysis was accomplished using a Dohrman microcoulometer with both solid and liquid injection systems. Samples were burned in oxygen atmosphere at 800°C and flushed into a coulometric cell containing silver ion. Chloride then reacts with the silver decreasing the amount of silver ion available in the solution which is measured by the coulometer.

Ionic chlorine samples were combusted by oxygen flask, absorbed in dilute hydrogen peroxide solution, and worked up by ion selective electrode.

Total Organic Carbon

Total organic carbon samples were introduced by a solid injection system into a Dohrman total organic carbon analyzer. The organic carbon was combusted in oxygen atmosphere to CO_2 which was then passed through a nickel catalyst, converted to methane, and detected by flame ionization detector.

Sulfur

Sulfur analysis samples were combusted in an oxygen flask combustion system, absorbed in hydrogen peroxide solution, precipitated with barium chloride and weighed as barium sulfate.

Trace Element Analysis

The liquid portions of the slurry samples were submitted to the Physical Science Center of Monsanto Company in St. Louis for trace element determination. The samples were analyzed by Atomcomp technique employing an inductively coupled argon plasma (ICAP) excitation source. The analysis requires no preparation of liquid samples as the sample is injected directly without dilution or concentration.

RESULTS

The results of the analyses performed are shown in Tables D-2, D-3, and D-4.

Table D-2 shows the results of the total chlorine, ionic chlorine, total organic carbon, and sulfur analyses on the solid samples and the solid and liquid fractions of the slurry samples. All results are expressed as concentrations.

TABLE D-2. CONCENTRATIONS OF TOTAL AND IONIC CHLORINE, TOTAL ORGANIC CARBON AND SULFUR IN ALL SAMPLES

Sample	Total chlorine by microcoulometer, ppm Cl	Ionic chlorine, ppm Cl⁻	Total organic carbon[a]	Total organic carbon, H_2O extractable, mg/l	Sulfur via O_2-flask combustion with $BaSO_4$
Solid samples and solid phase of slurry samples					
Dry ESP composite, 8/19/76	15; 20; 17	<29	771; 780 μg/g		0.43; 0.44%
Pyrite, utility plant, 8/18/76	1,496; 1,325[b]	<28	25.18; 26.26, 24.66%	20	24.35; 20.59%
Pulverizer in glass	2,272; 2,239[b]	58	66.32; 66.72%	26	3.79; 2.87%
Dry ESP composite, 8/18/76	16; 14; 15	<20	627; 634 μg/g		0.57%
ESP fly ash, 8/19/76, 12:29-1:20 p.m.	19; 21; 17	<18	1.67; 1.74%		0.68; 0.52%
ESP fly ash, 8/18/76, 8:30-9:20 a.m.	16; 17; 15	<17	2.29; 2.22%		0.57; 0.47%
Bottom ash, 8/19/76 - powder	7; 9				
- chunks	21; 28	<18	1.82; 1.51%		0.24; 0.15%
Bottom ash, 8/18/76, 3:27-3:55 p.m.	13; 13; 13	<19	0.82; 0.68%		0.05; 0.04%
ESP fly ash, 8/18/76, 2:46-3:58 p.m.	35; 38; 34	<17	2.08; 2.00%		0.54; 0.32%
Liquid phase of slurry samples					
Bottom ash, 8/19/76	19	<8	5.8; 6.4 mg/l		52; 54 ppm
ESP fly ash, 8/18/76, 2:46-3:58 p.m.	32	<9	3.0; 3.6 mg/l		7; 6 ppm
Bottom ash, 8/18/76, 3:27-3:55 p.m.	20	<10	6.8; 6.1 mg/l		36; 29 ppm
ESP fly ash, 8/18/76, 8:30-9:20 a.m.	10	<9	4.5; 3.6 mg/l		7; 8 ppm
ESP fly ash, 8/19/76, 12:29-1:20 p.m.	14	<9	10.5; 9.1 mg/l		12; 9 ppm

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[a] Expressed as percent carbon where indicated.

[b] The high values for total chlorine by microcoulometer were probably due to interference from the very high sulfur content of these samples.

TABLE D-3. POLYCYCLIC ORGANIC MATERIALS - GC/MS[a]

Component	Dry ESP composite, 8/19/76 - μg/g			Pyrite, 8/18/76 - μg/g			Pulverizer, 8/18/76 - μg/g			Dry ESP composite, 8/18/76, μg/g		
	Fraction			Fraction			Fraction			Fraction		
	2	3	4	2	3	4	2	3	4	2	3	4
Dibenzothiophene	N.D.	N.D.	N.D.	N.D.	0.421	0.521	N.D.	1.422	0.466	N.D.	N.D.	N.D.
Anthracene/phenanthrene	N.D.	N.D.	N.D.	N.D.	9.037	6.502	N.D.	24.932	8.966	N.D.	0.0231	0.0118
Methyl-anthracenes/-phenanthrenes	N.D.	N.D.	N.D.	N.D.	14.545	13.076	N.D.	48.004	16.432	N.D.	0.045	N.D.
9 - Methyl-anthracene	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.
Dimethyl-anthracenes/-phenanthrenes	N.D.	N.D.	N.D.	N.D.	17.236	14.967	N.D.	53.903	19.315	N.D.	0.0434	N.D.
Fluoranthene	N.D.	N.D.	N.D.	N.D.	0.364	1.223	N.D.	1.012	1.427	N.D.	N.D.	N.D.
Pyrene	N.D.	N.D.	N.D.	N.D.	1.758	1.474	N.D.	4.116	1.612	N.D.	0.0231	N.D.
Methyl-fluoranthenes/-pyrenes	N.D.	N.D.	N.D.	N.D.	4.497	10.236	N.D.	16.349	18.830	N.D.	N.D.	N.D.
Benz(c)phenanthrene	N.D.	N.D.	N.D.	N.D.	0.417	1.351	N.D.	0.611	1.039	N.D.	N.D.	N.D.
Chrysene/benz(a)anthracene	N.D.	N.D.	N.D.	N.D.	1.857	7.298	N.D.	4.132	15.024	N.D.	N.D.	N.D.
7, 12 - Dimethyl-benz(a)anthracenes(or isomers)	N.D.	N.D.	N.D.	N.D.	17.658	18.844	N.D.	20.908	24.485	N.D.	N.D.	N.D.
Benzofluoranthene(s)	N.D.	N.D.	N.D.	N.D.	0.350	1.715	N.D.	1.136	3.713	N.D.	N.D.	N.D.
Benzopyrene(s)(and perylene)	N.D.	N.D.	N.D.	N.D.	0.426	1.502	N.D.	1.553	4.757	N.D.	N.D.	N.D.
3 - Methylcholanthrene	N.D.	N.D.	N.D.	N.D.	N.D.	1.754	N.D.	0.684	1.796	N.D.	N.D.	N.D.
Indeno(1, 2, 3 - cd)pyrene	N.D.	N.D.	N.D.	N.D.	N.D.	1.270	N.D.	N.D.	1.985	N.D.	0.0127	N.D.
Dibenz(a, h)anthracene	N.D.	N.D.	N.D.	N.D.	N.D.	1.038	N.D.	N.D.	2.835	N.D.	N.D.	N.D.
Dibenz(c, g)carbazole	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.
Dibenzopyrenes	N.D.	N.D.	N.D.	N.D.	N.D.	3.436	N.D.	0.606	3.189	N.D.	N.D.	N.D.

[a] Detection limit for Colbert pyrite and pulverizer is 0.5 μg; for all other samples, limit is 0.025 μg.

N.D. - Not detected.

(continued)

TABLE D-3 (continued)

	ESP fly ash, 8/18/76						ESP fly ash, 8/19/76					
	Liquid phase extract, μg/l			Solids portion, μg/g			Liquid phase extract, μg/l			Solids portion, μg/g		
	Fraction						Fraction					
Component	2	3	4	2	3	4	2	3	4	2	3	4
Dibenzothiophene	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.
Anthracene/phenanthrene	N.D.	0.056	0.161	N.D.	0.002	N.D.	N.D.	0.845	0.331	N.D.	0.002	N.D.
Methyl-anthracenes/-phenanthrenes	N.D.	0.119	0.305	N.D.	0.002	N.D.	N.D.	1.01	0.553	N.D.	0.005	N.D.
9 - Methyl-anthracene	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.
Dimethyl-anthracenes/-phenanthrenes	N.D.	0.161	0.393	N.D.	0.003	N.D.	N.D.	0.804	0.431	N.D.	0.005	N.D.
Fluoranthene	N.D.	0.088	0.084	N.D.	<0.002	N.D.	N.D.	0.092	0.128	N.D.	N.D.	N.D.
Pyrene	N.D.	0.174	0.160	N.D.	<0.002	N.D.	N.D.	0.193	0.160	N.D.	N.D.	N.D.
Methyl-fluoranthenes/-pyrenes	N.D.	N.D.	0.123	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.
Benz(c)phenanthrene	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.
Chrysene/benz(a)anthracene	N.D.	N.D.	0.047	N.D.	N.D.	N.D.	N.D.	0.093	0.047	N.D.	N.D.	N.D.
7, 12 - Dimethyl-benz(a)anthracenes(or isomers)	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.
Benzofluoranthene(s)	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	0.071	N.D.	N.D.	N.D.	N.D.
Benzopyrene(s)(and perylene)	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	0.062	0.035	N.D.	N.D.	N.D.
3 - Methylcholanthrene	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	0.248	N.D.	N.D.	N.D.	N.D.
Indeno(1, 2, 3 - cd)pyrene	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.
Dibenz(a, h)anthracene	N.D.	N.D.	0.066	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.
Dibenz(c, g)carbazole	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.
Dibenzopyrenes	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.

N.D. - Not detected.

(continued)

TABLE D-3 (continued)

	Bottom ash, 8/18/76						Bottom ash, 8/19/76					
	Liquid phase extract, µg/l			Solids portion, µg/g			Liquid phase extract, µg/l			Solids portion, µg/g		
	Fraction						Fraction					
Component	2	3	4	2	3	4	2	3	4	2	3	4
Dibenzothiophene	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	0.007	0.04	0.007
Anthracene/phenanthrene	N.D.	0.299	0.064	N.D.	0.010	N.D.	N.D.	0.498	0.430	0.02	0.03	0.041
Methyl-anthracenes/-phenanthrenes	N.D.	0.315	0.125	N.D.	0.017	N.D.	N.D.	0.581	0.466	0.03	0.78	0.068
9 - Methyl-anthracene	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	<0.003	0.003	<0.003
Dimethyl-anthracenes/-phenanthrenes	N.D.	0.097	0.068	N.D.	0.017	N.D.	N.D.	0.459	0.439	0.01	0.78	0.058
Fluoranthene	N.D.	0.073	N.D.	N.D.	0.003	N.D.	N.D.	0.095	1.29	<0.003	0.03	0.007
Pyrene	N.D.	0.382	0.127	N.D.	0.003	N.D.	N.D.	0.141	1.07	<0.003	0.061	0.010
Methyl-fluoranthenes/-pyrenes	N.D.	0.017	N.D.	N.D.	N.D.	N.D.	N.D.	0.045	0.296	<0.003	0.24	0.047
Benz(c)phenanthrene	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	0.071	<0.003	0.003	<0.003
Chrysene/benz(a)anthracene	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	1.04	<0.003	0.085	0.041
7, 12 - Dimethyl-benz(a)anthracenes(or isomers)	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	<0.003	0.580	0.021
Benzofluoranthene(s)	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	<0.003	0.02	0.02
Benzopyrene(s)(and perylene)	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	0.270	<0.003	0.02	0.034
3 - Methylcholanthrene	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	<0.003	0.027	0.014
Indeno(1, 2, 3 - cd)pyrene	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	<0.003	0.034	0.044
Dibenz(a, h)anthracene	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	<0.003	0.03	0.047
Dibenz(c, g)carbazole	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	<0.003	<0.003	0.027
Dibenzopyrenes	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.

N.D. - Not detected.

TABLE D-4. TRACE METAL CONCENTRATIONS IN FILTRATE OF ASH SLURRY SAMPLES

Trace metals, Jarrell ash Atomcomp metals (ppm)	Sample - filtrates tested			
	Bottom ash, 8/18/76, 3:27-3:55 p.m.	Bottom ash, 8/19/76	ESP fly ash, 8/18/76, 2:46-3:58 p.m.	ESP fly ash, 8/19/76, 12:29-1:20 p.m.
Ag	<0.1	<0.1	<0.1	<0.1
Al	0.1	0.1	<0.1	<0.1
Ba	<0.1	0.1	0.8	1.2
B	<0.1	0.3	5.0	9.4
Ca	28.9	96.1	483.0	555.0
Cd	<0.1	<0.1	<0.1	<0.1
Co	<0.1	<0.1	<0.1	<0.1
Cr	<0.1	<0.1	0.1	0.1
Cu	<0.1	<0.1	<0.1	<0.1
Fe	0.2	<0.1	<0.1	<0.1
Mg	3.1	0.3	<0.1	<0.1
Mn	<0.1	<0.1	<0.1	<0.1
Mo	<0.1	<0.1	1.2	1.8
Na	5.7	6.8	16.7	22.3
Ni	<0.1	<0.1	0.1	0.1
Pb	<0.1	<0.1	<0.1	<0.1
Sb	<0.1	<0.1	<0.1	<0.1
Si	2.9	4.6	1.6	0.7
Sn	<0.1	<0.1	<0.1	<0.1
Sr	0.1	0.1	0.7	0.9
Ti	<0.1	<0.1	<0.1	<0.1
V	<0.1	<0.1	<0.1	<0.1
Zn	<0.1	<0.1	<0.1	<0.1
P	<0.1	<0.1	<0.1	<0.1
Be	<0.1	<0.1	<0.1	<0.1
Zr	<0.1	<0.1	<0.1	<0.1
As	<0.1	<0.1	<0.1	<0.1

The total chlorine analysis was performed in triplicate on several of the solid and solid phase samples because of the concern over homogeneity. The bottom ash sample from 8/19/76 was divided into two size ranges, powder and "chunks", and analyzed for total chlorine. The results indicated that the "chunks" of bottom ash had total chlorine concentrations three times higher than the powdered bottom ash, justifying the original concern.

The pyrite and pulverizer samples both contain very high levels of sulfur (22% and 4%), causing difficulty with the total chlorine analysis of these samples. When the sulfur content exceeds 100 times that of the chlorine in the sample, significant sulfur interference is noted. The remainder of the samples ranged in total chlorine concentration from 10 ppm to 40 ppm, with the liquid portions showing no significant difference from the solid portion. Likewise, the bottom ash samples did not differ from the fly ash samples in total chlorine. The ionic chlorine results showed no significant difference from one sample to the other with all samples but one having ionic chlorine concentrations less than 30 ppm Cl^-.

Total organic carbon was highest, as expected, in the pulverizer and pyrite samples: 67% and 25%, respectively. Dry ESP samples were between 600 ppm and 800 ppm TOC while the solid phase of the ESP slurry samples were between 1.5% and 2.3% TOC. It appears that slurrying of the ash leaches out inorganics concentrating the organic carbon. All liquid phase samples contained 3 to 11 mg/l total organic carbon. A total organic carbon analysis was run on water extractions of the coal and pyrite to determine the amount of organic carbon that is water extractable from the fuel prior to combustion. The procedure extracted a weighed sample with 100 ml of distilled water for 8 hours using a hot plate, water cooled condenser and Soxhlet extractor. The pyrite sample extracted weighed 5.52 grams and the pulverzier sample weighed 5.09 grams. The results indicate that about 500 mg of organic carbon can be extracted from one kilogram of pulverized coal as compared with about 350 mg/kg of pyrite.

As mentioned above, sulfur content was high in the pulverizer and pyrite samples: 4% and 22%, respectively. Ash samples and solid portions of ash slurry samples had sulfur content below 1%. The filtrate portion of these samples contained 5 ppm to 50 ppm sulfur with the bottom ash filtrate about five times higher in sulfur content than the fly ash filtrate.

Table D-3 lists the results of the POM analyses. Sample size is listed in the column heading as grams for solid samples and as milliliters for liquid samples. Eight samples were analyzed for POM's. The sample not analyzed was the ESP fly ash sample taken on 8/18/76 from 2:46 - 3:58 p.m. The analyst understood this sample to be a backup sample of the ESP sample taken on 8/18/76, 8:30 - 9:20 a.m., and thus omitted it from the POM analytical work.

As noted in the tables, most POM's were below the detection limits except in the case of the pulverized coal and pyrite samples where the total POM's were 303 ppm and 153 ppm, respectively.

Table D-4 lists the results of the trace metal analysis performed on the filtrate of four slurry samples. Trace metals found in excess of 1 ppm were Ba, B, Ca, Mg, Mo, Na, and S, with calcium being highest. Trace metals ranged from 30 ppm to 100 ppm in the bottom ash filtrate, and 450 ppm to 650 ppm in fly ash filtrate. The remaining concentrations were from 1 ppm to 25 ppm, with most being less than 10 ppm. An analysis of the water prior to slurrying would be needed to verify that the trace metals were leached from the ash.

GLOSSARY

air preheater: Device that preheats combustion air using waste heat recovered from flue gas.

affected population: Number of persons around an average source who are exposed to a source severity greater than 0.05 or 1.0, as specified.

ash sluicing: Transport of ash as aqueous slurry.

beneficiation: Physical cleaning of coal to remove mineral matter.

bituminous: Coal covering a wide range of properties, but in general having a fixed carbon content less than 80% and volatile matter exceeding 20%.

blowdown: Boiler water or cooling water wasted from a closed circulatory system to limit the buildup of dissolved solids.

boiler efficiency: Ratio of boiler heat output, measured as the heat content of the steam produced, to boiler heat input, measured as the heat content of the coal feed.

boiler tubes: Cylindrical tubes, located in convection passes and on furnace side walls, in which heat from the furnace is transferred to the boiler water.

bottom hopper: Container fitted to bottom of furnace to collect ash that falls to furnace floor.

capacity: Maximum heat or maximum steam output for which boiler is designed.

clarification: Removal of suspended solids from feedwater by quiesent settling.

combustion zone: Layer surrounding each coal particle where the mixing of combustibles and air forms a combustible mixture, and a diffusion flame is established.

criteria pollutants: Pollutants for which ambient air quality standards have been established.

cyclone: Device that uses centrifugal forces to separate particulate matter from gas.

diffusion flame: Flame established around a solid where combustible material must diffuse into the oxidant in order for combustion to take place.

direct feed: Fuel supply system in which coal is fed directly from pulverizers to burners.

dispersed concentration: Concentration of water pollutant in receiving body after mixing.

dry bottom furnace: Furnace in which operating temperature is kept below ash fusion temperature so that bottom ash can be removed as dry powder.

economizer: Device that preheats boiler feedwater using waste heat recovered from flue gas.

effluent factor: Quantity of effluent species discharged per quantity of mass burned.

emission factor: Quantity of emission species emitted per quantity of mass burned.

enrichment: Concentration of certain elements in fly ash due to their partitioning behavior at furnace temperatures.

evaporator: Device used to purify boiler feedwater by thermal vaporization.

excess air: Air added to furnace in excess of that required for stoichiometric combustion.

exchange capacity: Maximum quantity of dissolved ions that can be adsorbed by an ion exchanger without breakthrough occurring.

external combustion: Combustion which takes place outside of the working fluid of a heat-to-work conversion device; all boilers require external combustion.

firing capacity: Maximum amount of heat input for which a furnace is designed.

fixation: Solidification of waste sludges by addition of chemicals.

flue gas dew point: Temperature at which vapors in flue gas begin to condense.

fly ash: Portion of noncombustible residue from fuel, carried out of boiler by flue gas.

hardness: Concentration of scale-forming ions in water.

hazard factor: Lowest concentration of pollutant which has been shown to be detrimental to health or environment.

horizontally fired furnace: Furnace in which burners are located in side walls.

indirect feed: Fuel supply system in which coal leaving pulverizers is fed to a storage hopper which supplies the burners.

ion exchange: Reversible interchange of ions between a liquid and a solid with no radical change in the structure of the solid; used for purification of boiler feedwater.

output capacity: Maximum quantity of steam at given pressure which a boiler is designed to generate.

overfire air: Combustion air admitted to furnace just above flame.

partitioning: Separation of a substance between two phases.

pulverized: Finely divided; at least 80% of pulverized coal will pass through a 200-mesh sieve.

pulverizer: Device that crushes coal to fineness necessary for combustion in a pulverized, coal-fired furnace.

pyrolysis: Chemical decomposition by application of heat in oxygen-deficient atmosphere.

reheater: Heat exchange device for adding superheat to steam which has been partially expanded in a turbine.

slag: Molten form of noncombustible fuel residue remaining in furnace after combustion.

softening: Removal of hardness-causing ions from water using chemical precipitation or ion exchange.

source severity: Indication of the hazard potential of an emission source.

staged combustion: Fuel-rich combustion achieved by diverting portion of combustion air to port near tip of flame.

state emission burden: Ratio of annual emissions from a specific source in any state to the total state emissions from all stationary sources.

superheater: Device for heating steam to a temperature above that corresponding to saturation at a specific pressure.

tangentially fired furnace: Furnace in which burners are located in corners and directed toward the edges of an imaginary circle in the center of the furnace, thus imparting a swirling motion to the flames.

threshold limit value (TLV): Airborne concentrations of substances; represents conditions under which it is believed that nearly all workers may be repeatedly exposed day after day without adverse effect.

utilization factor: Ratio of actual output of boiler, as required by demand, to related output.

vertically fired furnace: Furnace in which burner is located in furnace ceiling and directed downward.

water quality criteria: Concentrations of selected pollutants at which damage to selected biological species has been shown to occur.

water walls: Furnace walls composed of boiler tubes.

wet bottom furnace: Furnace in which operating temperature is above ash fusion temperature so that portion of ash remaining in furnace is in molten form.

CONVERSION FACTORS AND METRIC PREFIXES [128]

CONVERSION FACTORS

To convert from	To	Multiply by
Degree Celsius (°C)	Degree Fahrenheit (°F)	$t_{°F} = 1.8\, t_{°C} + 32$
Gram/kilogram (g/kg)	Pound/ton	2.000
Joule (J)	Btu	9.478×10^{-4}
Kilogram (kg)	Pound-mass (avoirdupois)	2.205
Meter (m)	Foot	3.281
Meter (m)	Inch	3.937×10^{1}
Meter^2 (m^2)	Mile^2	3.861×10^{-7}
Meter^3 (m^3)	Foot^3	3.531×10^{1}
Metric ton	Ton (short, 2,000 pound mass)	1.102
Pascal (Pa)	Inch of water (60°F)	4.019×10^{-3}
Second (s)	Minute	1.667×10^{-2}

PREFIXES

Prefix	Symbol	Multiplication factor	Example
Exa	E	10^{18}	1 Em = 1 x 10^{18} meters
Peta	P	10^{15}	1 Pm = 1 x 10^{15} meters
Tera	T	10^{12}	1 Tm = 1 x 10^{12} meters
Giga	G	10^{9}	1 Gm = 1 x 10^{9} meters
Mega	M	10^{6}	1 Mm = 1 x 10^{6} meters
Kilo	k	10^{3}	1 km - 1 x 10^{3} meters
Milli	m	10^{-3}	1 mm = 1 x 10^{-3} meter
Micro	μ	10^{-6}	1 μm = 1 x 10^{-6} meter

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[129] Standard for Metric Practice. ANSI/ASTM Designation E 380-76$^{\varepsilon}$, IEEE Std 268-1976, American Society for Testing and Materials, Philadelphia, Pennsylvania, February 1976. 37 pp.